

2009/2010

British Columbia Utilities Commission Annual Report

DOC
BC
U9
B:B2
2009/10
c. 3

Contents

4	Message from the Chair & Chief Executive Officer
8	Organizational Overview
20	The Year in Review
36	Financial and Administration
38	Financial Report
45	Summary of Decisions, Reasons for Decision and Negotiated Settlements issued in 2009/2010
74	I Staff List
75	II Regulated Utilities
80	III Natural Gas Marketers Licensed in 2009/2010
81	IV Domestic Electricity Sales - 2009
82	V Domestic Gas Sales - 2009
83	VI Main Electric Transmission and Power Generating Facilities (Map)
84	VII Natural Gas and Gas Liquids Utilities (Map)
85	VIII Performance Indicators Hearing/Alternative Dispute Resolution Days (Fiscal 2009/2010) Customer Complaints and Inquiries (Fiscal 2009/2010) Gas Marketer Complaints/Disputes Staffing Levels Directives Issued Commission Expenditures and Cost of Regulation per Customer Cost of Energy Regulation per Equivalent Gigajoule of Energy Sold Cycle Times
95	IX Summary of Commission Orders issued in 2009/2010
118	X Standard Abbreviations & Acronyms
119	XI Glossary of Terms
122	XII Energy Conversion Factors



BRITISH COLUMBIA
UTILITIES COMMISSION

The Commission's mission is to ensure that ratepayers receive safe, reliable and nondiscriminatory energy services at fair rates from the utilities it regulates, and that shareholders of those utilities are afforded a reasonable opportunity to earn a fair return on their invested capital.



Message from the Chair and Chief Executive Officer

CHANGE

Change continues to dominate the agenda for the Commission; responding to change this past year and for the foreseeable future is a key challenge for the Commission and the organizations it regulates. Policy actions arising from the BC Energy Plan are gaining momentum and regularly drive or influence applications that come before the Commission. Following decisions in 2009 from the BC Court of Appeal, assessing the adequacy of First Nations consultation is an important consideration in many of the applications that come before the Commission. The Section 5 Transmission Inquiry, which is a major undertaking of the Commission, commenced on schedule in the spring with the usual scoping, procedural and scheduling steps only to then be delayed by an unexpected jurisdictional matter. After having dealt with this matter and now ready to proceed, Government suspended the Inquiry pending its consideration and policy response to the Green Energy Task Force Groups. In the circumstance, the Commission supported the suspension. Looking forward, the Government recently announced Bill 17 – 2010 Clean Energy Act and corresponding changes to the Utilities Commission Act. It is clear that change will continue and the Commission has demonstrated it has the resilience and capacity to respond.

OBJECTIVES

To respond to change, the Commission set a number of objectives last year and they remain relevant and active today. These objectives serve to focus attention and efforts on operational and organizational priorities that improve the execution of the Commission's mandate and build capability and capacity to meet future requirements as they evolve. These objectives drive change and direct activity at the Commission, both collectively and individually, and are reflected to a great degree in all personal performance plans. The objectives are:

- 1/ Move to a more inclusive relationship with key stakeholders
- 2/ Demonstrate a knowledge of and support for the Energy Plan
- 3/ Recognize and accommodate expanding decision making scope
- 4/ Build competence and a depth of capability at the Commission
- 5/ Support fair participation in Commission proceedings
- 6/ Make greater use of technology to further Commission objectives and become more efficient and effective.

Progress continues in all objectives; however of particular note is the success on objective 4 - building competence and a depth of capability at the Commission. We have been successful in acquiring very talented professionals in the areas of finance, engineering, First Nations engagement, and administration. In addition, staff and Commissioners have benefited from an ongoing and stimulating internal professional development program. Utility staff, intervenor groups, and BCUC staff and contractors have been very helpful in providing much of the technical component to this initiative and we appreciate their assistance. Several professional development days and external development focussed on individual needs round out the program. Under the objective to build competence and a depth of capability, knowledge transfer and succession planning also remain key areas of attention. Overall, these initiatives have been very effective and are making efficient use of scarce resources. Our culture as a learning organization is now well established at the Commission.

FIRST NATIONS

The decisions in 2009 of the British Columbia Court of Appeal confirmed the Commission is obligated to assess the adequacy of Crown consultation with First Nations within the scheme of its regulation. The Commission found it required additional and specialized resources to respond appropriately to these decisions. Following some initial assistance by way of a secondment from the BC Environmental Assessment Office, the Commission added a staff specialist to lead work in this area. Considerable success has been achieved in extending this

specialized knowledge and capability across the organization. Revised Certificate of Public Convenience and Necessity filing Guidelines incorporating First Nations requirements were developed and issued to provide guidance to Crown and non-Crown utilities when preparing certain applications for consideration by the Commission. The Commission now routinely assesses First Nations consultation in a relatively broad range of applications; however, challenges continue as parties seek to establish legal clarification in this new decision making area.

FINANCIAL MANAGEMENT

Commission activities related to the administration of the Utilities Commission Act are not funded by Government, but by the organizations it regulates through an annual levy and specific charges to applicants for the hearings the Commission undertakes on their behalf. The specifics are set out in section 125 of the Utilities Commission Act and BC Regulation 283/88. The Commission operates with a budget which was most recently set based on 2007 planning criteria although the work of the Commission has evolved considerably since that time. The Commission has in the past operated within the budget; however, this year, due to the unique nature of the Transmission Inquiry expenses, and unexpected information technology and occupancy charges, the Commission concluded the year over budget. Costs remain within the budget when Transmission Inquiry expenses, unexpected costs, and first time accruals are considered as exceptions. In the coming year the budget will be reassessed in light of the current and emerging role of the Commission.

MANDATORY RELIABILITY STANDARDS

The BC Energy Plan recognizes that for British Columbia to participate as an importer or exporter of electric power it must remain consistent with certain regulations and standards of operation designed to protect the integrity of the North American power system. The Utilities Commission Act gives the Commission exclusive jurisdiction to determine whether a reliability standard should be adopted in British Columbia and once adopted, to then monitor ongoing compliance. This important initiative has been a work in progress for over a year involving consultation with specialists from BC's electric utilities, industry stakeholders, the Ministry of Energy Mines and Petroleum Resources, the Commission, and officials from United States regulatory agencies. In December this major project was complete. Mandatory reliability standards have been established, operators are moving to ensure compliance, and a cost effective compliance monitoring regime using existing resources is in place.

ANNUAL REPORT

Section 12 of the Utilities Commission Act requires the Commission to submit a report to the Lieutenant Governor in Council for the preceding year setting out a brief summary of all applications and complaints, Commission findings, and reporting on other matters considered to be in the public interest. Consistent with previous annual reports, the reporting timeframe is for the fiscal year and reflects the jurisdiction of the commission at that time. Pursuant to the Utilities Commission Act and the Budget Transparency and Accountability Act, I respectfully submit this report on the activities of the British Columbia Utilities Commission for the fiscal year 2009/2010.

The success of the Commission in carrying out its important work on behalf of the citizens and businesses of British Columbia is the result of ongoing dedication and professionalism of our staff and Commissioners. This annual report provides an opportunity to recognize their contribution and to formally recognize and thank them. I also thank the many stakeholders who participated in Commission processes in the past year.



Len Kelsey
Chair & Chief Executive Officer



Len Kelsey
Chair and Chief Executive Officer



Introduction

The British Columbia Utilities Commission, located in Vancouver at 900 Howe Street, is a regulatory agency of the Provincial Government, operating under and administering the Utilities Commission Act. The Commission's function is quasi-judicial and it has the power to make legally binding rulings. Decisions and orders of the Commission may be appealed to the Court of Appeal on questions of law or jurisdiction.

The Commission's primary responsibilities are the regulation of utilities under its jurisdiction and the regulation of certain aspects of automobile insurance pursuant to the Insurance Corporation Amendment Act. The Administrative Tribunals Act also applies to matters before the Commission. In addition to its primary responsibilities, the Commission has regulatory responsibilities under the Utilities Commission Act for electricity transmission facilities, energy supply contracts and the issuance of gas marketer licenses. The Commission also reviews energy-related and basic automobile insurance matters referred to it by Cabinet. These reviews usually involve a public inquiry followed by a report and recommendations to Cabinet. As well, under Part 7 of the Pipeline Act, the Commission establishes tolls and conditions of service for intraprovincial oil pipelines.

Through an open and transparent regulatory review process, the Commission ensures that:

- rates charged for energy are fair, just, and reasonable;
- energy utility operations provide safe, adequate, and secure service to their customers;
- the shareholders of public utilities under its jurisdiction are afforded a reasonable opportunity to earn a fair return on their invested capital;
- Insurance Corporation of British Columbia (ICBC) universal compulsory automobile insurance is adequate, efficient, just and reasonable; and
- ICBC optional insurance is not subsidized by other ICBC operations.

Kathy Grasty





The Commission is self-funded; its costs are recovered primarily through a levy on the organizations it regulates. The work of the Commission is important to the citizens and businesses of British Columbia because regulation instils a high degree of public confidence that competing interests between monopolies, consumers and other stakeholders are reconciled. Likewise, regulation sends a message beyond British Columbia that the province is a safe and fair place to do business.



The Utilities Commission Act provides for the appointment of a Chair and Commissioners by the Lieutenant Governor in Council. During the 2009/2010 fiscal year, a Chair who is also a Commissioner, one full-time Commissioner and eight part-time Commissioners, served as members at the Commission. As well, 27 Commission staff, including business specialists, professional engineers, accountants, economists, and administrative staff supported the Commission's work. Commission staff are organized into an Information Services Group, three specialist professional divisions, and a group responsible for the electricity transmission inquiry. The activities of the Commission are supported by the finance and administration department.



(top) Brian Williston

(middle) Mark Thomas

(bottom) Eileen Cheng

Several years ago, the Commission established a vision, mission, and value statement. The Commission remains committed to these, as stated below:

Vision

To be a respected regulator of public utilities.

Mission

The Commission's mission is to ensure that ratepayers receive safe, reliable, and nondiscriminatory energy services at fair rates from the utilities it regulates, and that shareholders of those utilities are afforded a reasonable opportunity to earn a fair return on their invested capital.

Value Statements

The Commission is committed to:

- Ensure arms-length, independent, and accountable regulation of utilities and ICBC.
- Apply regulatory principles, research and industry knowledge to resolve problems concerning public utilities or the regulated portion of automobile insurance.
- Render decisions that are timely, fair, workable, and respected.
- Write high quality decisions, reports, and publications.
- Communicate effectively and transparently with co-workers, utilities, ratepayers, government and the public.
- Promote learning, innovation, creativity and the achievement of personal and professional goals.

In addition to its regulatory responsibilities, the Commission provides the following services and assistance:

- reviews ratepayers' complaints about the actions of utilities, ICBC and independent gas marketers;
- adjudicates gas marketing disputes;
- provides copies of documentation prepared by the Commission (e.g. brochures, guidelines, orders, decisions, etc.). These documents are also posted and available for download from the Commission's web site: www.bcuc.com;
- provides access to the Tariffs of regulated utilities and to the Code of Conduct and Rules for Gas Marketers;
- provides access to information filed in public hearings;
- responds to requests for general information regarding utilities and ICBC; and
- responds to requests for information regarding participating in Commission processes and making applications to the Commission.

Commission regulatory functions and other responsibilities are carried out by panels of Commissioners and Commission staff. A panel of Commissioners is assigned to review and make final determinations on applications and other matters before the Commission. Commissioners also meet regularly to authorize the issuance of orders or other directives, to review complaints and to conduct other necessary Commission business. Commission staff use an interdisciplinary team approach to carry out their responsibilities, normally composed of professionals from the disciplines of engineering, accounting, and economics.

and is advised, as appropriate, by legal counsel and specialist consultants.

BRITISH COLUMBIA UTILITIES COMMISSION STAFF

Information Services Group

The Information Services group, led by the Commission Secretary, includes an Assistant Commission Secretary, a Customer Choice Administrator, a Customer Service Specialist, a Web Administrator and several support positions. The Commission Secretary acts as the official contact for both regulated organizations and the public. The department responds to all requests for information; receives and investigates natural gas marketer and utility customer complaints; prepares periodic reports and quarterly regulatory updates; provides research support; website services; library services and media interaction; and maintains the Commission's information resources and database of mailing lists.

Professional Divisions

The professional divisions consist of staff specialists with expertise and experience in the areas of accounting, economics, ratemaking, business, and engineering. The functions of these divisions include the review of financial, accounting, social, First Nations consultation, and economic aspects of energy utility activities and ICBC's basic automobile insurance. The professional divisions also review energy supply and demand, including conservation impacts, and the reliability aspects of energy production, transmission, and distribution. In considering a matter under review by the Commission, these professionals have a

Peter Vivian



responsibility to ensure the development of a full record of evidence. This often requires that staff be technical advisors to the Commission, and provide external expert witnesses to testify at hearings.

In 2009/2010, the professional divisions also included an electricity transmission group responsible for providing support to an inquiry into British Columbia's long-term electrical transmission requirements. The inquiry, as required under the Utilities Commission Act, was suspended by Government in December 2009.

Financial Administration Office

The financial administration office conducts background research and prepares decision support for executive policies and provides a range of administrative, financial, intra-governmental and human resources services, the Chair and CEO, Commissioners and staff.

The organizational chart below shows the reporting structure within the Commission.

BRITISH COLUMBIA UTILITIES COMMISSION ORGANIZATIONAL CHART

OFFICE OF THE CHAIR

Len Kelsey, Chair & Chief Executive Officer

FINANCIAL ADMINISTRATION

Viki Vourlis, Manager of Finance, Human Resources,
Administration & Assistant to the Chair/CEO [2]

INFORMATION SERVICES

Erica Hamilton, Commission Secretary [8]

COMMISSIONERS

Alison Rhodes
Peter Vivian
Robert (Bob) Milbourne
Liisa O'Hara
Anthony Pullman
Keith Anderson
Michael Harle
Ross Ravelli
Dennis Cote [9]

STRATEGIC SERVICES

Doug Chong, Director [3]

RATES & FINANCE

Philip Nakoneshny,
Director [4]

ENGINEERING & COMMODITY MARKETS

Brian Williston, Director [4]

SECTION 5 TRANSMISSION INQUIRY

Jim Fraser, Director

ORGANIZATIONAL OVERVIEW



(photo left – left to right)
Engineering and Commodity Markets: Mark Thomas, Bob Brownell,
Don Flintoff, Brian Williston, Roy Bishop (Consultant).

(photo below – left to right)
Commissioners Anthony Pullman, Ross Ravelli, Peter Vivian, Michael
Harle, Bob Milbourne, Dennis Cote, [front left to right] Alison Rhodes,
Liisa O'Hara.



(photo above middle) Alison Richter, Mark Thomas.

(photo above) Erica Hamilton.

(photo right – left to right)

Senior Management Team: Brian Williston,
Jim Fraser, Viki Vourlis, Len Kelsey,
Philip Nakoneshny, Erica Hamilton, Doug Chong.



(photo right – left to right) Financial Administration:
Denise Goddard, Viki Vourlis, Kim Brooks.

(photo below – left to right) Information Services Group:
Christopher Winkers, Alison Cormack, Kathy Grasty, Mark Hudson,
Jenelyn Torres, Yvonne Lapierre, Daniela Guest, Erica Hamilton,
Kristen Olsen, Constance Smith.



(photo above – left to right)
Rates and Finance: Claudia McMahon,
Yolanda Domingo, Philip Nakoneshny,
Kristine Bienert.

(photo right – left to right)
Strategic Services: Eileen Cheng, Alison
Richter, Tony Roberts, Doug Chong.



(photo above middle) Kristen Olsen.

(photo above – left to right) Yolanda
Domingo, Peter Vivian, Jenelyn Torres,
Doug Chong, Eileen Cheng.



Commissioner Biographies

LEN F. KELSEY,
CHAIR AND CHIEF EXECUTIVE OFFICER

Vice President, British Columbia Automobile Association (18 years); Chief Operating Officer, BCAA Insurance Corporation, retired 2002; past Member B.C. Committee, Insurance Bureau of Canada; Public Administrator and past Chair, North Shore Health Region; independent Business Consultant, appointed July 2008. Prior to appointment as Chair, acted as a Commissioner for the British Columbia Utilities Commission from 2003-2008.

ALISON A. RHODES,
COMMISSIONER

University of British Columbia (B.A. - economics major); University of Western Ontario (LL.B, MBA); Called to British Columbia Bar 1984; Practiced law (civil litigation) from 1984 to 2004; Vice President, Jardine Lloyd Thompson Canada from 2004 to 2008; appointed December 2007.

DENNIS A. COTE,
COMMISSIONER (PART-TIME)

Educated at Simon Fraser University (Bachelor of General Studies); retired in 2007 as the Vice President, Product Development and Support for the British Columbia Automobile Association (BCAA); he held various other executive roles with the BCAA which include Vice President Sales, Director of Travel Services, Merchandise Investment Manager and Store Manager with the Hudson Bay Company, BC Region, Vice President and board member with the Alliance of Canadian Travel Agents of British Columbia; currently a Travel Industry Advisory Group Member with Consumer Protection BC; appointed October 2008.

ROBERT J. (BOB) MILBOURNE,
COMMISSIONER (PART-TIME)

University of British Columbia [B.Sc. Metallurgical Engineering]; P.Eng. (B.C., Ontario); Stelco Inc., retired as Senior Executive and Member of the Board of Directors 1996; Principal, Milbourne and Company (Business Advisors) 1997; Hatch Associates Ltd., Director 1997-2002; Bruce Power Inc., Director 2001-2005; Member Ontario Human Rights Commission from 1991-1996; Member, BC Securities Commission 2002; appointed August 2003.

PETER E. VIVIAN,
COMMISSIONER (PART-TIME)

University of Toronto [Bachelor of Applied Science - Electronics]; University of Western Ontario [Bachelor of Law]; Flight Lieutenant, RCAF; Professor of Law at the universities of Western Ontario, Ottawa and Victoria; General Manager, Canadian Law Information Council from 1975-77; various positions with the BCE Inc. group of companies from 1977-97; Vice President and Chief of Staff, The Business Council on National Issues (now the Council of Canadian Chief Executives) from 1982-84, 1989-90; Executive Director, Telecommunications, CRTC from 1998-2000; Principal, Vivian Associates, Consultants to Management (2000-present); appointed August 2003.

LIISA A. O'HARA,
COMMISSIONER (PART-TIME)

University of British Columbia [M.Sc., Business Administration]; Certified General Accountant. A senior pipeline executive; retired from Terasen Pipelines in 2004 as Vice President, Financial Services and Regulatory Affairs after 21 years of service. Prior to a career in the energy industry, enjoyed an eight year career in the airline industry where employed by CP Air in various financial and regulatory affairs roles. Served as Executive-In-Residence at Sauder School of Business from 2005 to 2009. As a graduate of Institute of Corporate Directors, certified with the ICD.D designation in 2006, serves as a professional corporate director on various corporate boards; appointed January 2005.

ANTHONY J. PULLMAN,
COMMISSIONER (PART-TIME)

Keble College Oxford [B.A. 1967, M.A. 2001]; Chartered Accountant; retired from the ATCO Group in 2004 after 24 years of service; Vice President Controller Alberta Power Limited from 1980-1985; Vice President Controller and Vice President Planning and Budgeting ATCO Ltd. from 1985-1993; Senior Vice President Finance ATCO Power Ltd. from 1993-2004; Chairman Calgary District Hospital Group from 1989-1991; Chairman Alberta Blue Cross Plan from 1996-1998; appointed March 2006.

A.W. (KEITH) ANDERSON,
COMMISSIONER (PART-TIME)

Bachelor of Commerce, University of Alberta, Chartered Accountant; Retired from Pricewaterhouse-Coopers as partner responsible for PwC's energy utilities practice in Canada; over 35 years experience as a strategic planning, financial, and regulatory consultant in the energy and other sectors including gas, electric and pipeline utilities, financial institutions, telecommunications and transportation companies; independent financial and management advisory consultant serving as a director of and advisor to private corporations; appointed July 2006.

**MICHAEL R. HARLE,
COMMISSIONER (PART-TIME)**

Bachelor of Commerce (Carleton); Chartered Accountant (Ontario and Alberta) and Certified Management Consultant (Alberta). Over forty years experience as a professional consultant and business executive; retired from IBM where for the past five years he was the Partner responsible for IBM Global Business Services for the Alberta and Saskatchewan Public Sectors, including government, health, and education. Prior to that he spent 35 years with PricewaterhouseCoopers Consulting and its predecessor companies where he was partner responsible for public sector services in the Prairie Provinces and northern Canada; appointed December 2008.

ROSS K. RAVELLI, COMMISSIONER (PART-TIME)

The owner of Ravelli Farms Ltd, a third generation 2,500 acre grains and oilseeds farm bordering the City of Dawson Creek. An extensive career in farm organizations beginning in the late 1980s; initially focused on provincial issues, over the past ten years has had the opportunity to lead two national organizations, the Canadian Canola Growers Association (President 2002-06) and recently completed his second term and was also President of the 80,000 member Grain Grower of Canada Organization. Has traveled extensively both nationally and internationally representing the interests of both Canadian agriculture and Canadian agricultural producers; Appointed as Director for Farm Credit Canada, the largest Canadian lender to the agriculture industry, appointed November 2008.

SPECIAL DIRECTIVES

Following is a general description of the Special Directives received during 2009. The complete text of the Special Directives can be found on the Commission's website at [www.bcuc.com/About the BCUC/ Special Directives](http://www.bcuc.com/About%20the%20BCUC/Special%20Directives).

Order in Council No. 074

Approved February 17, 2009 - Amendments to sections 4 and 7 of Special Direction HC2 to increase BC Hydro's revenue requirements for fiscal years 2010, 2011, and 2012, affording BC Hydro the opportunity to earn its previously determined pre-income tax annual return on equity plus an additional 1.63 percent and to allow BC Hydro to establish a deferral account for fiscal year 2010 to defer for later recovery the difference between the revenue required before and after the amendments.

The Commission's March 13, 2009 decision subsequently authorized BC Hydro to establish a Return on Equity Adjustment Regulatory Account to defer the impact of the incremental rate of return, authorized by Special Direction HC2 and Order in Council No. 074, on BC Hydro's fiscal year 2010 revenue requirement.

Ministerial Order No. M 039

Approved February 22, 2009 - Ministerial Order M 039 references Mandatory Reliability Standards adopted under section 125.2 (6) of the Utilities Commission Act and specifies the owners of transmission, distribution and generation facilities, and the direct users of the bulk power system, to which the reliability standards apply.

Order in Council No. 205

Approved and Ordered March 12, 2009 - The Commission must allow BC Hydro to establish a regulatory account for future recovery of net costs arising from its home purchase program associated with the Vancouver Island Transmission Reinforcement (VITR) Project and that the Commission must not reconsider or rescind the project certificate for the VITR project because of BC Hydro's home purchase program.

Ministerial Order No. M 114

Approved March 30, 2009 - Specifies contents of a report required under section 43.1 of the Utilities Commission Act. For the required report, BC Hydro must provide the Commission annually with a comparison of BC Hydro's rates with those charged by public utilities in other North American jurisdictions.

Order in Council No. 494

Approved and Ordered September 23, 2009 - Amends Special Direction IC2 to the Commission revising the definitions of "capital available" and "MCT" (Minimum Capital Test) as they apply to ICBC.

Order in Council No. 565

Approved and Ordered October 28, 2009 - The Commission must allow BC Hydro to plan to rely on its Burrard Thermal generating plant for no more than 900 megawatts of capacity and zero firm energy per year.

The Year in Review

INTRODUCTION

The Commission regulates public utilities and intra-provincial pipelines under its jurisdiction and certain aspects of the automobile insurance provided by ICBC. It does so within an evolving framework of legislation, court judgments and the province's energy policy as set out in its 2007 Energy Plan: "A Vision for Clean Energy Leadership."

A significant change to the legal framework occurred late in the previous fiscal year. On February 18, 2009, the British Columbia Court of Appeal in *Carrier Sekani Tribal Council v. British Columbia (Utilities Commission)*, 2009 BCCA 67 and *Kwikwetlem First Nation v. British Columbia (Utilities Commission)*, 2009 BCCA 68 confirmed that where the duty to consult is triggered, the Commission has the obligation to assess the adequacy of Crown consultation with First Nations within the scheme of its regulation. The Commission, in its role as a quasi-judicial tribunal, does not itself have an independent duty to consult First Nations. Rather, it is the Crown who has a legal duty to consult First Nations when making decisions that may affect Aboriginal and treaty rights.

This finding by the court added a substantial new dimension to the review of many applications. The Commission has actively been building capacity and educating staff in this new area of responsibility.

Another change to the legal framework was foreshadowed in the February 9, 2010 Speech from the Throne wherein it was indicated that the Province will be reviewing British Columbia's regulatory regimes, including the BC Utilities Commission. At the time of preparing this annual report, the Province has released Bill 17-2010 Clean Energy Act, intended to strengthen the clean energy sector. The Clean Energy Act exempts certain BC Hydro projects and programs from the need for Commission approval. The Commission will continue to regulate BC Hydro's domestic supply and rates and the safety and reliability of the BC Hydro system. The Commission will also continue to regulate BC Hydro's operating, management and administrative costs and handle ratepayer complaints regarding BC Hydro service.

In the past year, the Commission's activities fell into the following key functional areas:

- Revenue Requirements - determining how much revenue a regulated company would require to carry out its business;
- Rate Design and Tariffs - deciding how a regulated company should collect its approved revenue, how rates should be structured, and reviewing issues related to a company's tariff;

- Facilities and planning - reviewing utilities' long-term plans to ensure that they will continue to provide safe, reliable service at reasonable cost to customers, and reviewing shorter term plans to construct new facilities, to modify existing ones, and to purchase energy for supplying to their customers. The Commission also undertook to update guidelines related to the Commission's new mandate to assess the adequacy of consultation with First Nations;
- Regulation of natural gas marketers;
- Establishment, in collaboration with Government and BCTC, of Mandatory Reliability Standards for the electricity transmission system; and
- Establishment of the procedural and legal framework for the electricity transmission inquiry prior to its suspension in late 2009.

FIRST NATIONS INITIATIVES

Following the Carrier Sekani and Kwikwetlem British Columbia Court of Appeal decisions in February 2009, which held that the Commission has a duty to assess the adequacy of Crown consultation with First Nations, the Commission has significantly increased, and continues to develop, its capacity in this area.

The Carrier Sekani decision, which considered a BC Hydro electricity purchase agreement, was appealed to the Supreme Court of Canada. The Supreme Court granted leave to appeal and a decision is pending.

The Kwikwetlem decision directed the Commission to reconsider a Certificate of Public Convenience and Necessity awarded to BCTC for its Interior to Lower Mainland transmission project. The reconsideration was directed to assess the adequacy of Crown consul-

tation with First Nations. The reconsideration process began in March 2009 and an oral public hearing took place in January 2010. A Commission decision is expected in the summer of 2010.

Following the Court of Appeal decisions, many Crown utility filings received by the Commission this past year have contained a First Nations component for assessment. To aid in its assessment of Crown consultation, the Commission issued revised draft Certificate of Public Convenience and Necessity filing guidelines and new draft First Nations information filing guidelines for public comment in September 2009. After consideration of the comments received, the Commission issued the final guidelines in March 2010.

REVENUE REQUIREMENTS AND RETURN ON EQUITY

When a regulated company, such as an energy utility or ICBC, applies for revenue requirements, it asks the Commission to approve a certain amount of forecast revenue that it will be allowed to collect in one or more subsequent years. For energy utilities, applications include a forecast of the utility's expected costs for each of those years and a forecast of the expected customer demand for energy. The forecasts typically include costs such as operating and maintenance, new capital additions, energy efficiency programs, labour, and financing costs, including interest on debt and a reasonable return on equity (ROE) for its shareholders.

Once the Commission has determined the allowable costs and approved a forecast of energy demand, the average effect on rates can be determined. For ICBC, costs typically include operating, claims and financing costs, as well as the cost of maintaining adequate reserves of capital to allow it to provide the required basic automobile insurance.

In some instances, the Commission avoided lengthy and costly hearings by engaging in a negotiated settlement process involving the affected utility, ratepayer groups and Commission staff, wherein a performance or incentive-based formula has been negotiated for determining the revenue requirement over several years.

In 2009/2010 the Commission reviewed revenue requirements applications from:

- Terasen Gas Inc., Terasen Gas[Vancouver Island] Inc. and Terasen Gas [Whistler] Inc. for 2010-2011
- FortisBC Inc. for 2010
- Pacific Northern Gas Ltd. and Pacific Northern Gas [N.E.] Ltd. for 2010

RETURN ON EQUITY

A specific component of revenue requirements, and one which is often the subject of its own applications and hearings for investor-owned utilities, is the ROE that investors should achieve for their investment in the utility. The courts have been clear that the Commission must allow investors in regulated utilities the opportunity to earn a fair rate of return on their utility investment.

In 1994, the Commission established the ROE using a formula based on the yield of Canada long-term bonds plus an equity risk premium and, for some utilities, an additional utility-specific risk premium. Because of the unusual economic circumstances beginning in late 2008, the formula for setting ROE was challenged in 2009. In 2009/2010, the Commission received two applications related to ROE:

- A Return on Equity and Capital Structure Application from Terasen Gas Inc., Terasen Gas [Vancouver Island] Inc., Terasen Gas [Whistler] Inc.

The Terasen Application, which was filed on May 15, 2009, requested that the Commission eliminate the use of the automatic adjustment mechanism in the determination of its return on equity. The application was reviewed by an oral hearing and the Commission issued its Decision on September 16, 2009. A summary of the Commission's decision can be read in the Decision Summaries section of this report.

- An Application for approval of a Capital Structure and Equity Risk Premium for Pacific Northern Gas Ltd. (PNG-West Division) and Pacific Northern Gas [N.E.] Ltd. (Fort St. John/Dawson Creek and Tumbler Ridge Divisions)

The PNG application was filed on July 16, 2009 and the Commission ordered that the application be reviewed under a negotiated settlement process which occurred in April 2010.

ICBC

ICBC did not file a revenue requirements application in 2009; consequently, there was no consideration of a general rate change for Basic Insurance during the year. Following approval by the Commission on a Revised Terms of Reference, ICBC issued an Expression of Interest for an independent third party to review the allocation of regional claim centre costs. The Commission received the completed report in November 2009. After receiving comments on the report, the Commission directed ICBC to implement the report's recommendations subject to some adjustments.

During the 2009/2010 fiscal year, the Commission reviewed an application by ICBC for a process to streamline its Basic Insurance revenue requirements applications. The application review included an information session, working sessions, and written submissions before the Commission approved a streamlined rate setting process on April 6, 2010. The approval includes a tiered approach to set Basic Insurance rates annually. An actuarial rate indication above 2.5 percent will require a full revenue requirement application process while an indication, at or below 2.5 percent qualifies for a streamlined rate review process. If an indication is within the band of +/- 1 percent and ICBC is not required to seek a rate change; ICBC has the option to file an Actuarial Certificate along with specified supporting documentation to set Basic Insurance rates.

RATE DESIGN AND TARIFF MATTERS

Rate design is the process by which utility rates are established for each customer class. Generally, a rate design follows the determination of a utility's revenue requirement. The revenue requirement defines how much revenue the utility requires from all customers and sources and the rate design determines how much revenue is to be collected from each customer class. A key objective in rate design is to set rates that recover revenues from each customer class in proportion to the costs to serve each class.

Determining how much each customer class contributes to a utility's costs is based on a cost of service analysis. This analysis apportions the costs for generation (electricity) or acquisition (electricity or natural gas), transmission, and distribution between customer classes on the basis of each class's contribution to system requirements. While some costs are directly attributable to a particular customer class, many are shared between classes. Shared costs create the need for a cost allocation method which may be based on the percentage of the equipment used to serve a class, the ratio of the labour force dedicated to a class or the amount of the class's energy use that occurs at periods of peak demand. Debate over allocation methods often accounts for the majority of a rate design hearing.

Rate Design also considers the structure of the rates for each class. Utility bills generally contain several parts such as a monthly fixed charge, an energy charge (charge per unit of energy) and, for many large volume customers, a demand charge (a charge based on maximum energy use in a given period). Some utilities also have time-of-use rates or stepped

rates that increase or decrease as consumption rises within the billing period. The common objectives in setting a rate structure are fairness, simplicity, and ease of understanding. Another objective, set out by the Province's Energy Plan, is that utility rate designs should encourage energy efficiency and conservation.

For ICBC, rate design means establishing the base premiums for compulsory Basic Insurance. In common with utility rate design, ICBC's total revenue requirement is recovered through the rate premium revenues. However, automobile insurance premiums differ from utility rate design in that base rates include the likelihood of specific customer class's future claims costs. Actuarial analysis is used to estimate future costs and is incorporated into proposed base rates.

The tariff of each regulated company sets out the rates for, and the terms and conditions of, service for the company. The rate design process establishes the rates that are published in the tariff. From time to time, the Commission reviews applications for changes to the terms and conditions of service or disputes about the interpretation of the terms and conditions in the tariff.

The Commission reviewed six major rate design or tariff related applications during fiscal year 2010.

BCTC Open Access Transmission Tariff

The British Columbia Transmission Corporation (BCTC) provides transmission service throughout the area served by BC Hydro, as well as trans-border transmission between BC and Alberta and the United States. Because BC engages in significant electricity trade with the US, BCTC's tariff must be consistent with the standard open access transmission

tariff (OATT) determined by the US Federal Energy Regulatory Commission (FERC). Due to recent OATT amendments by FERC, BCTC submitted an updated tariff in November 2008 for Commission review. At about the same time, TransCanada energy filed a complaint filed against BCTC concerning services between BC and Alberta. The Commission reviewed the matters in a hearing and eventually accepted the amended OATT but denied TransCanada's complaint, although it directed BCTC to change how it conducts its BC-Alberta service.

FortisBC 2009 Rate Design

FortisBC provides electricity services to the central interior and Kootenay regions of BC. FortisBC was created in 2004 when Fortis Pacific Holdings Inc. purchased Aquila Networks Canada (formerly West Kootenay Power). The change of ownership, the subsequent purchase of Princeton Light & Power by FortisBC, and changes to the Utilities Commission Act, meant that a comprehensive rate design for the FortisBC service area had not been done since 1997. The Commission is currently reviewing a new rate design for FortisBC submitted by the utility in November 2009.

FortisBC Net Metering

A net metering program allows a customer who generates electricity to sell any surplus energy to the utility. FortisBC's application in April 2009 to introduce net metering as part of its tariff was approved by the Commission.

TGVI Rate Design

Terasen Gas Vancouver Island (TGVI) provides gas service to core market and transportation service customers. Core market customers (mainly residential, commercial, and small industrial customers) purchase the natural gas commodity from TGVI and have it delivered on TGVI's distribution and transmission pipes. Transportation customers are primarily large industrial consumers who purchase their natural gas from producers or aggregators and arrange for transportation of the gas on TGVI's transmission system.

TGVI filed a rate design for Commission review in July 2009. TGVI proposed to reduce transportation service rates to reflect recent cost decreases, while maintaining core market rates. TGVI has received a provincial subsidy which was historically required by its predecessor Centra Gas to introduce natural gas service to Vancouver Island. When the subsidy expires in 2011, TGVI rates will need to rise to reflect full costs. TGVI proposed maintaining core market rates, rather than dropping and then raising them, to provide a smoother transition. The application was reviewed through a negotiated settlement process and an agreement on rates was reached which was generally consistent with the proposals in the application.

BC Hydro Large General Service Rate Application

On October 16, 2009 BC Hydro filed its Large General Service Rate Application. BC Hydro seeks to establish new energy rates for its Large General Service customers, comprised primarily of institutional, large commercial and small industrial customers. The main reason for the new rates is to encourage energy conservation by charging a higher rate for more energy

consumed. The new energy rate schedules proposed by BC Hydro will result in the splitting of the existing class into two new rate classes: Medium General Service and Large General Service. The Medium General Service rate will flatten the current declining block rate structure, which charges a lower unit rate at higher levels of consumption. The new Large General Service rate will be a two-part rate structure based on an individual account's historical consumption level with the second part of the rate equalling BC Hydro's long run marginal cost of new energy supply. The Commission ordered the regulatory review process for this application to be conducted under a negotiated settlement process, which began on March 29, 2010.

RESOURCE PLANS

The Utilities Commission Act requires utilities to file long-term resource plans with the Commission. A long-term resource plan should include energy forecasts, before and after demand side measures, and plans for the construction or extension of facilities and energy purchases to meet energy requirements. BC Hydro is specifically required to file electricity demand forecasts and a statement of the demand side measures that it would need to take so that, in addition to demand side measures taken by the federal, provincial, or local governments, the demand increase would be reduced by 50 percent by 2020. The Commission reviews the long-term resource plans based on considerations stipulated in the Utilities Commission Act, such as the government's energy objectives, the public interest, the adequacy of cost-effective demand side measures, and if applicable, electricity self-sufficiency for the province.

Significant proceedings related to Resource Plans in 2009/2010 included:

- BC Hydro 2008 Long Term Acquisition Plan
- PNG West Pipeline System Resource Plan

BC Hydro 2008 Long Term Acquisition Plan

The June 2008 Long Term Acquisition Plan (LTAP) included BC Hydro's analysis of future natural gas prices, electricity prices, greenhouse gas prices, renewable energy credits, a demand side management (DSM) plan and a 20-year annual load forecast. Among other things, BC Hydro sought approval of expenditures totalling \$633.3 million and Commission endorsements of certain conclusions or proposals in the plan. An oral public hearing process reviewed the application.

In its July 27, 2009 decision, the Commission accepted various BC Hydro load forecasts and price forecasts for natural gas, electricity, greenhouse gas and renewable energy credits. It also endorsed BC Hydro reliance on its Burrard Thermal generating plant for planning purposes for 900 MW of capacity and the clean or renewable eligibility of the 2008 Clean Power Call. However, the Commission did not endorse the proposed target volume of the Clean Power Call and it rejected BC Hydro's DSM Plan.

In the decision, the Commission rejected the 2008 LTAP as a whole because it did not approve or endorse many substantial elements. The Commission directed BC Hydro, in its next LTAP, to present its electricity supply obligations and its plan for acquiring supply-side resources, if any, for a minimum period of 20 years and in accordance with the self-sufficiency criterion established by the Province.

PNG Resource Plan

In February 2009, Pacific Northern Gas Ltd. (PNG) filed a Resource Plan for its PNG-West Pipeline System. Past industrial closures in the PNG-West service area have depressed PNG revenues, but recent investor interest in establishing a liquefied natural gas operation could improve the system's economics. Commission review of the resource plan focused on whether PNG-West could establish a DSM program. PNG satisfied the Commission that incorporating a DSM program within the current environment was infeasible. PNG committed to introducing a DSM program in future resource plans, should the system's fortunes improve.

CAPITAL PROJECTS AND FACILITY APPLICATIONS

Certificates of Public Convenience and Necessity

The Utilities Commission Act requires regulated utilities to obtain from the Commission a Certificate of Public Convenience and Necessity (CPCN) before the utility begins the construction, extension, or operation of a public utility plant or system. Regulated energy utilities range from the very large ones familiar to most British Columbians, such as BC Hydro and Terasen Gas, to the electricity and propane utilities that serve small and isolated communities scattered throughout the province.

A CPCN application describes the project and provides information supporting the necessity of the project, including matters such as potential alternatives to the proposed project and activities undertaken to consult with First Nations, if necessary. The Commission must not approve a CPCN unless it is persuaded that the proposed facilities and associated operations and rates are appropriate, just and reasonable, and that the proposal properly conserves the public interest. Current CPCN applications and past decisions are available on the BCUC website.

The following CPCN applications were reviewed by the Commission in 2009/2010:

Pacific Northern Gas (N.E.) Tomslake Gas Distribution System

PNG proposed to expand its gas distribution system into the Tomslake community, located approximately 15 to 20 km south of Pouce Coupe, to bring natural gas service to approximately 250 rural households and six small commercial customers. A Certificate of Public Convenience and Necessity was granted by Order C-3-09.

BC Hydro Toad River Electrification Project

The Toad River project is the first project BC Hydro brought forward under its Remote Community Electrification Program. The prime objective of the program is for BC Hydro to provide reliable, safe and cost-effective electricity service by 2017 in all willing and eligible remote communities. There are approximately 30 to 40 eligible remote communities which are not part of the BC Hydro grid, are not in a "non-integrated area" that BC Hydro already serves, and are not otherwise provided with electricity by any public utility. The eligible communities comprise First

Nations communities which are located on reserve land and receive funding for electricity from the Federal Government through Indian and Northern Affairs Canada and civic communities, which are off-reserve and do not receive such funding. A Certificate of Public Convenience and Necessity for the Toad River Electrification project was granted by Order C-4-09A.

FortisBC Upgrade and Life Extension of the Corra Linn Unit 2 Generating Plant

FortisBC owns four generating plants containing 15 generating units, 11 of which are included in FortisBC's Upgrade and Life Extension program that commenced in 1997. The Corra Linn Plant, located on the Kootenay River midway along Highway 3A between the cities of Castlegar and Nelson, is comprised of three generating units and was constructed in 1932. The Corra Linn Unit 2 project is the last of the units in the Upgrade and Life Extension program. A Certificate of Public Convenience and Necessity was granted by Order C-5-09.

BCTC Market Operations and Development Project

BCTC's Market Operations and Development project is intended to replace obsolete technology with a new consolidated business system in order to reduce costs, streamline business information management, and allow BCTC to continue to meet regulatory and tariff requirements. The project was originally part of the BCTC F2010-F2011 Transmission System Capital Plan. The Commission directed BCTC to apply for a CPCN for the project and, following its review of BCTC's application, granted a Certificate of Public Convenience and Necessity by way of Orders C-6-09 and C-6-09A.

Terasen Gas Customer Care Enhancement Project

The project includes implementing a new customer information system by Terasen Gas, and returning key components of customer care services from an outside vendor to Terasen Gas. A Certificate of Public Convenience and Necessity was granted by Order C-1-10.

Terasen Gas Tilbury Property Purchase

In October 2009, Terasen Gas applied for a Certificate of Public Convenience and Necessity for the purchase of land adjacent to its existing Tilbury Liquid Natural Gas Plant for continued compliance with safety regulations and potential future expansion reasons. Order G-28-10 granted a CPCN for the project subject to certain conditions. Terasen Gas requested a reconsideration which the Commission granted, and after the reconsideration proceeding, issued Order G-68-10 amending the conditions.

OVERSIGHT OF UTILITY ENERGY SUPPLIES***Natural Gas Commodity Costs***

Natural gas prices across North America are influenced in the short term by weather, the price of competing fuels, and gas storage levels. Traditional longer-term influences are the North American economy, the number of gas wells drilled, crude oil prices, and other factors that affect the gas supply/demand balance. Recently the surge in North American natural gas supply, principally associated with prolific shale gas deposits and the push toward lower carbon fuels, promises to fundamentally change the gas dynamic in North America. At the very least, abundant, affordable gas supplies have decoupled gas from oil prices for now, and may even result in

significant changes to historic gas flow paths. Natural gas is poised to increasingly displace coal in electricity generation, and perhaps to increase significantly as a transportation fuel as well.

Market prices for natural gas across the North American continent increased sharply in the winter of 2000/01, and since then showed high volatility as gas demand became more weather dependent. Colder weather during February and March 2008 increased withdrawals from storage and caused spot and forward prices to increase significantly. Gas prices continued to move upward in step with increasing crude oil prices until June 2008, when they reached near-record levels of approximately \$11 per gigajoule in northern British Columbia. After peaking in summer 2008, oil and gas prices quickly tumbled during the remainder of 2008, with gas reaching a price of \$4 per gigajoule in March 2009. Gas prices rose steadily into the winter of 2009/2010 peaking at close to \$6 per gigajoule and falling to the \$3.50 per gigajoule range in the spring. Entering the winter of 2009/2010 natural gas storage levels were at a record high; this spring, storage levels were close to the five-year average, likely due to the effect of significantly reduced gas drilling rates in 2009.

In 2010, confidence in continued economic recovery and a positive outlook for both the price of gas and oil seems to be supporting an increase in drilling rates. Oil drilling rates are up significantly compared to 2009, and interest in gas drilling appears to be well supported by a forward price curve of \$6 plus per gigajoule. Stable natural gas prices with seasonal variability may persist for the next several years, supporting a healthy environment for both consumers and natural gas producers.

DEFERRAL ACCOUNTS

Although the Commission does not regulate the competitive market for the natural gas commodity, it requires utilities to provide quarterly reviews of gas prices and deferral account balances. Such deferral account mechanisms are intended to smooth changes in utility rates when gas prices change. The result is that customers tend to pay less than the full market price when gas prices are high and pay slightly more than the current market cost when gas prices are low. The Commission reviews utility gas supply contracting and hedging plans to ensure that, within the limits of market prices, the utilities purchase reliable supplies at the lowest cost possible.

BC Hydro Power Calls

BC Hydro is responsible for almost all of the power supply in our province and, as such, they are the generator and first purchaser of the electricity consumed by most British Columbians. BC Hydro owns and operates numerous power generating facilities, most notably some very large hydroelectric dams known as the heritage assets. BC Hydro also has significant gas fired generating facilities located

at the Burrard Generating Station near Vancouver.

The Province has mandated by Special Direction that the Burrard Generating Station cannot continue to be part of BC Hydro's base load power portfolio. Also, as BC's population and economy continues to grow, so does its need for electricity, notwithstanding continued conservation efforts.

The BC Energy Plan mandates that 90 percent of all electricity generated in the province must come from clean or renewable sources and that BC must achieve electricity self-sufficiency by 2016.

In order to meet the province's growing electricity needs and reduce our dependence on electricity not sourced from clean or renewable sources, BC Hydro has issued several Power Calls focused on electricity generated from clean or renewable sources (e.g. run-of-river, biomass, wind and solar). The Power Calls are requests for quotations (RFQs) for proponents to submit proposals to sell power to BC Hydro. BC Hydro reviews responses to the RFQs and enters into negotiations with the selected proponents, culminating in executed Electricity Purchase Agreements, which then must be filed with the Commission for review and acceptance.

BC Hydro has three active calls for power:

The Clean Power Call: focused on larger projects, typically larger than ten megawatts (MW) in generating capacity, that meet the definition of clean power;

The Bioenergy Call - Phase II: focused on projects that use biomass as a fuel source; and

The Standing Offer Program: focused on small, clean energy generators smaller than 10 MW.

Additional detail and information regarding BC Hydro's power calls is available on BC Hydro's website.

Over the 2009/2010 fiscal year, BC Hydro filed a number of purchase agreements with the Commission, totalling some 284 MW of generation capacity. The following Orders associated with each agreement accepted by the Commission can be found on the Commission's website:

2009/2010 ACCEPTED ENERGY PURCHASE AGREEMENTS

E-7-09	Standing Offer Program - Cypress Creek
E-8-09	Bioenergy Phase I/Celgar Creek / Kamloops Green Energy / PGWE 2008 / PGP Bio Energy
E-10-09	Bone Creek
E-11-09	Standing Offer Program - Fitzsimmons Creek
E-14-09	Dokie 1 Wind Project
E-16-09	Purcell Power Plant
E-17-09	Armstrong Wood Waste Cogeneration Plant
E-19-09	Standing Offer Program - Cedar Road LFG Project
E-6-10	Standing Offer Program - Canoe Creek

NATURAL GAS CUSTOMER CHOICE PROGRAM

The natural gas Customer Choice Program offers consumers a choice in their provider of the natural gas commodity. Independent gas marketers offer natural gas at long-term fixed prices, and customers may purchase natural gas from a gas marketer or from their local natural gas utility. Gas marketers sell fixed-rate agreements that vary in length from one to five years, and are available to both residential and business customers. The Customer Choice Program is overseen by the Commission and a summary of the complaints and disputes processed by the Commission in 2009/2010 is found in Appendix VIII Performance Indicators on pages 85.

Gas Marketer Profile

As of March 31, 2010, there were 14 natural gas marketers licensed by the Commission, 11 of which solicit both residential and commercial customers and three which service only commercial customers. As of March 31, 2010, 16 percent of eligible residential customers have chosen to participate in the Customer Choice Program, which is consistent participation as the previous year.

Improvements to the Customer Choice Program

Since the start of the Program in 2004 for commercial customers, and in 2007 for residential consumers, the Commission, with other program participants, has implemented measures to assist consumers in obtaining accurate and relevant information they need to make an informed decision to choose natural gas suppliers.

The second Customer Choice Annual General Meeting held in April 2009 reviewed the system enhancements since 2008, and the communication activities planned for 2009 and 2010. Participants at the meeting also discussed the concerns and suggestions of interested parties. Terasen Gas filed a report in October 2009 summarizing the changes and recommendations proposed by program participants during the Annual General Meeting.

The Commission reviewed the report and by Order A-3-10 directed changes to the Code of Conduct and Rules for Gas Marketers. One key issue considered was a revision to the Third Party Verification (TPV) call script, under which gas marketers are required to verify with a follow-up telephone call that a customer has agreed to purchase natural gas through the gas marketer. The Commission approved the requirement for a standardized TPV call script. Although a TPV requirement has existed since 2007, the Commission determined that it would initiate development of a standardized script to improve consistency with the spirit of the Code of Conduct for Gas Marketers. The Commission also approved a change to the TPV timing to provide the customer an opportunity to review the contract before confirming their understanding of the key elements of the offer.

- A second key issue considered was a revision to the Essential Services Model (ESM), which governs how gas marketers deliver gas to Terasen Gas for eventual delivery to the end customer. ESM supports Terasen Gas' obligations as the Supplier of Last Resort and provides smaller gas marketers with the ability to compete based on the supply of 100 percent load factor to Terasen Gas. In addition, under the ESM,

customer contracts can only be terminated on contract anniversary dates to minimize the costs associated with cancelling gas marketer contracts. The Commission determined that the ESM model should not change at that time since it ensures the reliability and low cost objectives of the Commission.

The Commission will continue to make changes to strengthen the Code of Conduct for Gas Marketers, and to strengthen its monitoring and enforcement of the requirements of the Code. The next Annual General Meeting is scheduled for September 8, 2010 in Vancouver. Gas Marketing representatives, a consumer advocacy group, and Terasen Gas Inc. are invited to attend.

MANDATORY RELIABILITY STANDARDS FOR THE BULK ELECTRICAL POWER SYSTEM

Following the 2003 blackout in the northeastern part of the continent, governments have taken steps to provide reliability standards for the bulk electrical power system in North America that are mandatory and enforceable. The 2007 BC Energy Plan stated that, because the province's transmission system is part of a much larger, interconnected grid, there is a need to work with other jurisdictions to maximize the benefits of interconnection, remain consistent with evolving North American reliability standards, and ensure British Columbia's infrastructure remains capable of meeting customer needs.

The May 2008 amendment to the Utilities Commission Act recognizes the North American Electric Reliability Corporation and the Western Electricity Coordinating Council (WECC) as reliability standard-making bodies for the bulk power system, and gives the Commission jurisdiction to determine whether a reliability standard should be adopted in British Columbia. Ministerial Order M 039 dated February 22, 2009 made the Mandatory Reliability Standards (MRS) Regulation, which prescribes the parties that are subject to adopted reliability standards.

In response to an Assessment Report from the British Columbia Transmission Corporation dated March 27, 2009, Commission Order G-67-09 adopted 103 reliability standards for application in British Columbia. Order G-123-09 adopted the Rules of Procedure, Registration Manual, and Compliance Monitoring Program for reliability standards in British Columbia. This Order also appointed WECC as Administrator to assist the Commission for the registration of parties that are subject to the standards and the monitoring of compliance with the standards.

The Commission sponsored a WECC Workshop on registration in Vancouver in December 2009. To the end of March 2010, the Commission has registered 11 parties as Responsible Entities for one or more of the functions identified in the standards.

BCTC filed MRS Assessment Report 2 on February 23, 2010 assessing one new reliability standard and 22 revisions to previously approved standards. Order G-36-10 established a written comment process for these standards, following which the Commission will determine those that are in the public interest and will apply in British Columbia.

LONG-TERM ELECTRICITY TRANSMISSION INQUIRY

Section 5 of the Utilities Commission Act directs the Commission to conduct an inquiry with respect to British Columbia's long-term infrastructure for electricity transmission, and to begin the inquiry by March 31, 2009. The Minister of Energy, Mines and Petroleum Resources specified terms of reference for the inquiry on December 11, 2008, which required the Commission to publish its draft inquiry report by June 30, 2010 for public comment before finalization and submission to government.

On March 24, 2009, the Commission issued Order G-30-09 which started the inquiry. During the spring and summer of 2009, the Commission hosted several workshops and procedural conferences. On December 15, 2009, the Minister sent a letter to the Commission stating that revised terms of reference for the inquiry will be issued after the Government has considered the recommendations of its Green Energy Advisory Task Force and made appropriate adjustments to the policy framework. Accordingly, the Minister stated that "...it would not be productive to continue with the Section 5 Inquiry before May 31, 2010, by which time the amended Terms of Reference will be available."

HIGHLIGHTS IN OPERATIONAL AND FINANCIAL PERFORMANCE

Proceeding Days

The number of proceeding days remained relatively consistent from 2008/2009 to 2009/2010 at 62 and 64 respectively (including hearings, procedural conferences, alternative dispute resolution, workshops, Community Input Sessions, and meetings related to annual reviews of Performance-Based Regulation agreements). There were 26 oral public hearing days in 2009/2010, as compared to 33 in 2008/09. There were five alternative dispute resolution days in 2009/2010 and 33 days dedicated to procedural conferences and workshops.

A summary of the decisions and orders issued by the Commission in 2009/2010 is found commencing on page 45 and 95 of this Annual Report respectively.

Organizational Efficiency and Effectiveness

In 2009/2010, the Commission had a compliment of a Chair, also serving as a Commissioner, one full-time Commissioner, and eight part-time Commissioners.

In 2009/2010 the Commission staff compliment was 27, which is an increase from 25 in 2008/2009. The increase is the result of a deliberate strategy to be less reliant on contractors for core competencies. Staffing expenditure constituted approximately 47 percent of the Commission budget in 2009/2010.

The Commission has the authority to grant cost awards to interveners in proceedings before the Commission. Following a review, the Commission approved revised Participant Assistance Cost Award

Guidelines in 2007 to ensure interveners' submissions are useful and not duplicative of other interveners' efforts, and that costs claimed are reasonable. In 2009/2010, the Commission issued 37 participant funding decisions totalling \$2,887,875.33, up from 24 funding decisions totalling \$494,107.06 in 2008/2009. The large increase was due to four very large hearings in 2009/2010 and over \$1 million of the increase followed the BC Supreme Court judgments in February 2009 requiring the Commission to assess the adequacy of consultation with First Nations, which resulted in strong participation by First Nations in the Long-term Transmission Inquiry and the reconsideration of the BCTC Interior to Lower Mainland Transmission project.

The costs of the Commission can be measured by cost per utility customer and cost per unit of energy sold. In fiscal year 2009/2010, the cost of regulation per customer¹ was \$1.14 up from \$0.88 in 2008/2009, and the cost of regulation per British Columbia resident² was \$1.48 for 2009/10 and \$1.19 for 2008/2009. The cost of regulation per gigajoule of energy sold in 2009/2010 was 1.64 cents, up from 1.23 cents in 2008/2009. The total expenditure for fiscal year 2009/2010 was \$6,671,922.02; the approved budget was \$6,156,000.00. While the Commission has operated within the budget in previous years, this year the Commission ended the year over budget due to the unique nature of the Transmission Inquiry costs as well as unexpected information technology and occupancy charges. When the Inquiry and unplanned for costs and first time accruals are considered as exceptions, Commission costs remain within budget. In the coming year the budget will be reassessed in light of the current and emerging role of the Commission.

¹Includes ICBC and energy regulatory customers.

²Census Canada 2008 and 2009 for British Columbia.

During the 2010/2011 fiscal year, the Commission expects to review the following major applications:

British Columbia Hydro and Power Authority

- Stave Falls Spillway Gates Replacement Project
- F2011 Revenue Requirements Application
- Keenleyside Spillway Gate Project

British Columbia Transmission Corporation

- Columbia Valley Transmission Project CPCN
- F2012 and F2013 Capital Plan
- Dawson Creek Area Reinforcement Project CPCN
- F2012 and F2013 Revenue Requirements

FortisBC Inc.

- Mandatory Reliability Standards Mitigation Plan
- Upper Bonnington Generating Plant Old Unit Repowering CPCN
- 2009 Resource Plan - Evidentiary Update
- 10-Year Demand Side Management Plan
- 2011 - 2012 Capital Expenditure Plan
- 2011 Revenue Requirements Application
- Advanced Metering Infrastructure CPCN

Insurance Corporation of British Columbia

- 2010 Revenue Requirements
- 3-Year Rate Design Adjustments

Pacific Northern Gas Ltd./Pacific Northern Gas (N.E.) Ltd.

- Kitimat LNG Terminal CPCN
- PNG (West) 2011 Revenue Requirements
- PNG (N.E.) 2011 Revenue Requirements

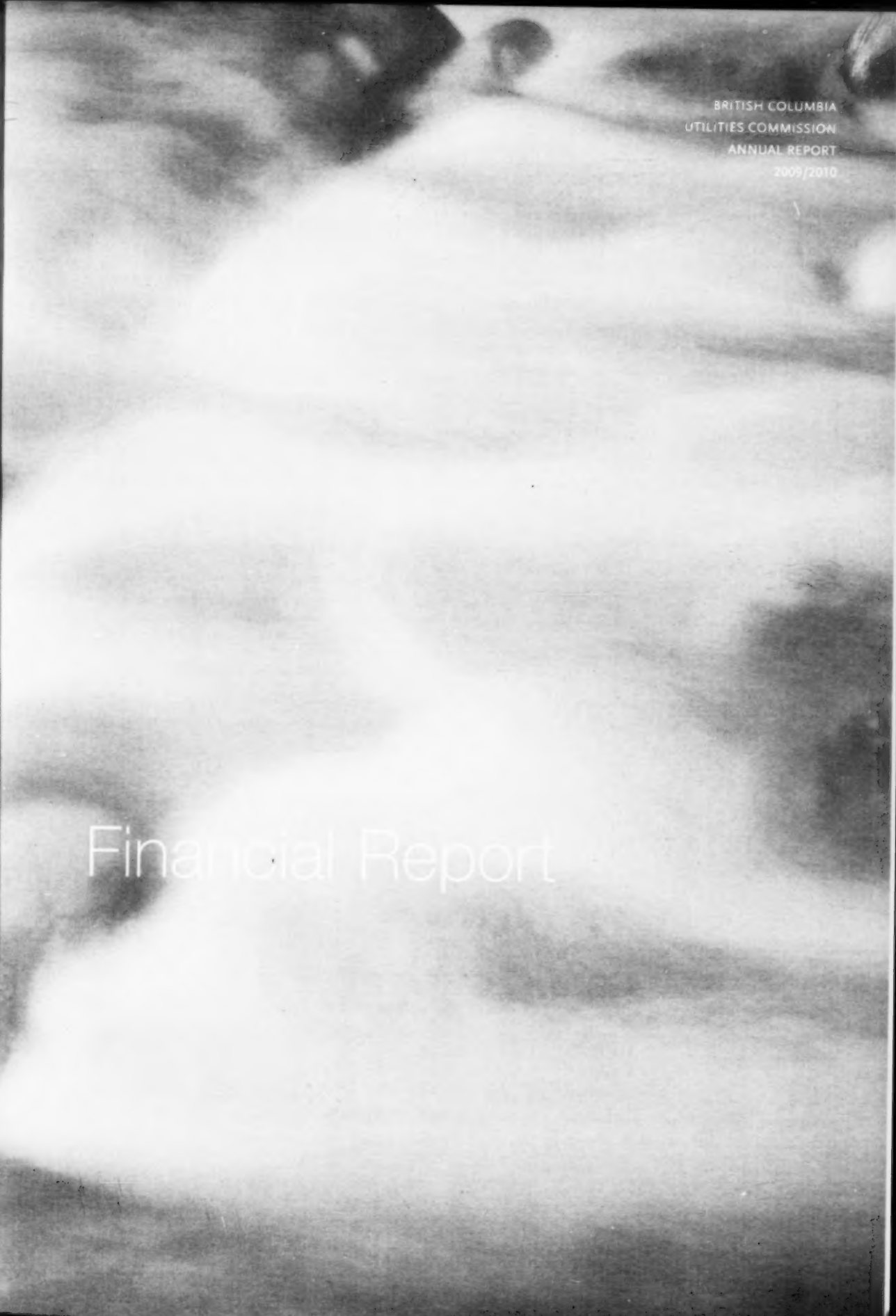
Shaw Cablesystems Limited/Shaw Business Solutions Inc.

- Application for Use of FortisBC Inc. Electricity Transmission Facilities

Terasen Gas Inc./Terasen Gas Vancouver Island Inc./Terasen Gas Whistler

- Gas Supply T-South Enhanced Service (TBO) Application
- Mt. Hayes LNG Storage Facility First Nations Investment
- Gas Supply Mitigation Incentive Program
- Biogas
- TGI Victoria Regional Office CPCN
- Fraser Mills District Energy System CPCN
- Kootenay River Crossing CPCN (Integrity)
- Resource Plans
- Huntingdon Bypass CPCN (Supply/Reliability)
- TGI Fort Nelson 2011 Revenue Requirements
- Advanced Metering CPCN





BRITISH COLUMBIA
UTILITIES COMMISSION
ANNUAL REPORT
2009/2010

Financial Report



AUTHORITY FOR COST RECOVERY

The Commission is authorized to recover its costs from regulated utilities and pipeline companies by fixing levies according to section 125 of the Utilities Commission Act and parameters set out in Levy Regulation, BC Reg. 283/88. The Commission recovers most of its costs by way of a "per gigajoule" levy assessed on each regulated utility, based on the amount of energy the utility sold in the previous calendar year (the calculation is provided below). The Insurance Corporation of British Columbia and British Columbia Transmission Corporation are billed separately for their annual regulatory costs as they do not sell energy.

The Commission also recovers proceeding costs directly from utilities for Commission expenditures attributable to public hearings and other proceedings under the Utilities Commission Act. Direct recoveries have varied significantly from year to year, depending on the number and duration of regulatory hearings and inquiries. Revenues are also collected from intra-provincial petroleum pipeline companies, natural gas marketers, and other utility regulatory agencies that contract with the Commission for advice and assistance.

2009/2010 REVENUES AND EXPENSES

Total Recoveries [Reference Page #, once complete]	\$ 7,007,329.54
Less: Expenditures [Reference Page #, once complete]	\$ 6,671,922.02
Revenue Deferred to 2010/2011 Levy	\$ 335,407.52

LEVY CALCULATION FISCAL 2010/11

Fiscal 2010/11 BCUC Budget [Total Budgeted Expenditures]	\$ 6,211,000.00
Less: 2009/2010 Deferred Revenue [Carried Forward 2010/11]	-335,407.52
Less estimated recoveries from:	
Natural Gas Marketers	-15,000.00
Intra-Provincial Oil Pipeline Companies & Upstream Gas Processors	-20,000.00
Insurance Corporation of British Columbia	-640,000.00
BC Transmission Corporation	-640,000.00
Expected Direct Recoveries from Public Hearings	-1,000,000.00
	-2,315,000.00
	<u>\$ 3,560,592.48</u>
Net BCUC 2010/11 Budget to be recovered through the Levy	\$ 3,560,592.48
Total Utility Energy Volumes sold in previous calendar year [GJ]	403,528,263
	<u>= \$ 0.00882365 /GJ</u>

The Commission's costs are expected to be recovered by a levy of \$0.00882365/GJ for the 2010/2011 fiscal year which is an increase over the 2009/2010 fiscal year levy from \$0.0076391318/GJ. Some of the increase in the levy is a result of lower energy volumes relative to a year earlier. The levy is payable by utilities in four quarterly instalments.

ANNUAL REPORT FIGURES 2009/2010

Commission Revenues Recovered Pursuant to Order G-56-09	Amounts Recovered 2009/10 Fiscal Year	Amounts Recovered 2008/09 Fiscal Year
British Columbia Hydro and Power Authority	\$ 1,231,437.61	758,029.08
British Columbia Transmission Corporation	560,000.00	480,000.00
Cal-Gas Inc.	140.38	80.70
Central Heat Distribution Limited	9,216.43	5,200.23
Corix Multi-Utility Services Inc.		
Gas	427.79	234.00
Electric	240.63	112.95
Corporation of the City of Nelson	1,557.43	895.62
FortisBC Inc.	52,818.87	44,881.62
Hemlock Valley Electrical Services Limited	106.95	24.21
Insurance Corporation of British Columbia	560,000.00	480,000.00
Pacific Northern Gas (includes Granisle Grid)	44,410.09	30,781.74
Dawson Creek and Fort St. John	32,111.09	18,787.74
Tumbler Ridge	7,312.55	3,723.66
Port Alice Gas Inc.	108.37	64.56
Big White Gas Utility	260.69	153.30
Silversmith Power & Light Corporation	-	n/a
Stargas Utilities Ltd.	227.00	133.14
Sun Peaks Utilities Co., Ltd.	601.37	334.86
Terasen Gas Inc.		
Revelstoke	1,330.17	843.18
Lower Mainland Division	846,371.88	500,511.57
Inland Division	329,285.73	212,345.46
Columbia Division	41,582.66	23,499.81
Fort Nelson Division	5,140.17	3,328.29
Terasen Gas (Vancouver Island) Inc.	234,035.30	143,609.04
Terasen Gas (Whistler) Inc.	4,886.18	2,993.46
The Yukon Electrical Company Limited	20.05	12.12
	\$ 3,963,629.39	2,710,580.34

ANNUAL REPORT FIGURES 2009/2010

Commission Revenues Recovered Pursuant to Order G-56-09	Amounts Recovered 2009/10 Fiscal Year	Amounts Recovered 2008/09 Fiscal Year
Natural Gas Marketer Licences		
Access Gas Services	\$ 1,000.00	2,000.00
Active Energy ULC	1,000.00	1,000.00
AG Energy Co-Operative/Firefly Energy	1,000.00	1,000.00
AltaGas Ltd	1,000.00	1,000.00
Cascadia Energy	1,000.00	
Connect Energy	1,000.00	
Direct Energy	1,000.00	7,000.00
Just Energy (BC) Limited	1,000.00	1,000.00
Just Energy (formerly Universal Energy Corporation)	1,000.00	8,000.00
MX Energy	1,000.00	1,000.00
Nexen Marketing	1,000.00	1,000.00
Planet Energy Corp	1,000.00	1,000.00
Shell Energy	1,000.00	1,000.00
Smart Energy (BC) Ltd	1,000.00	1,000.00
Summitt Energy BC LP	1,000.00	8,000.00
Superior Energy	1,000.00	1,000.00
	<u>\$ 16,000.00</u>	<u>35,000.00</u>

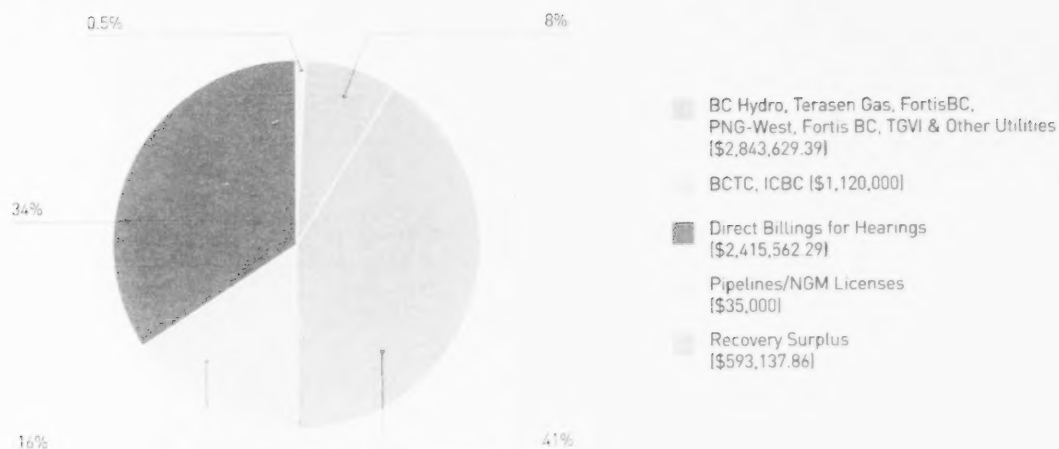
ANNUAL REPORT FIGURES 2009/2010

Commission Revenues Recovered Pursuant to Order G-56-09	Amounts Recovered 2009/10 Fiscal Year	Amounts Recovered 2008/09 Fiscal Year
Recoveries from Intra-Provincial Oil Pipelines and Other Companies		
AltaGas Ltd.	\$ 1,000.00	1,000.00
Canadian Natural Resources Limited - West Stoddard Plant	1,000.00	1,000.00
Enerplus Resources - Inga Oil	1,000.00	2,000.00
(Payment arrived late - carried forward to 10/11) Enerplus Resources - Inga Oil	-1,000.00	
Keyera Energy Ltd.	1,000.00	1,000.00
Kinder Morgan - Trans Mountain (Jet Fuel) Inc.	1,000.00	1,000.00
Plateau Pipeline - Blueberry	1,000.00	1,000.00
Plateau Pipeline - Northeast BC & Boundary Lake	1,000.00	1,000.00
Plateau Pipeline - Sunset Prairie	1,000.00	1,000.00
Plateau Pipeline - Taylor to Dawson Creek	1,000.00	1,000.00
Plateau Pipeline - Western System	1,000.00	1,000.00
Spectra Energy - Boundary Lake	1,000.00	1,000.00
Spectra Energy - Jedney I	1,000.00	1,000.00
Spectra Energy - Jedney II	1,000.00	1,000.00
Spectra Energy - Midwinter	1,000.00	1,000.00
Spectra Energy - Peggo	1,000.00	2,000.00
Spectra Energy - Sunrise	1,000.00	2,000.00
Spectra Energy - Tooga	1,000.00	1,000.00
Spectra Energy - West Doe & Hwy Processing & Pipeline Facilities	2,000.00	1,000.00
Spectra Energy - West Doe & Hwy Transportation & Processing Facilities	1,000.00	1,000.00
	\$ 19,000.00	21,000.00

ANNUAL REPORT FIGURES 2009/2010

Commission Revenues Recovered Pursuant to Order G-56-09	Amounts Recovered 2009/10 Fiscal Year	Amounts Recovered 2008/09 Fiscal Year
Miscellaneous Revenues		
Recovery of Proceeding Costs from Utilities	\$ 2,415,562.29	1,390,263.75
Recovery of Printing	0.00	508.30
Recovery of Hearing Room Rental	0.00	750.00
Deferred Revenue from 2008/09 [credited to utilities' quarterly billings in 2009/2010]	593,137.86	1,669,915.09
	3,008,700.15	
TOTAL REVENUES	\$ 7,007,329.54	\$5,828,017.48
Commission Expenditures 2009/2010		
Salaries & Benefits	\$ 3,116,354.68	2,563,676.35
Operating Costs	1,726,675.81	1,395,608.10
Professional Services	1,828,891.53	1,275,595.17
Total Expenditures	\$ 6,671,922.02	5,234,879.62
Deferred Revenue Carried Forward to 2010/11	\$ 335,407.52	

2009/2010 REVENUE



COMMISSION EXPENDITURES

The Commission's expenditures for fiscal year 2009/2010 were \$6,671,922.02 million, an increase of 27.45 percent over 2008/2009. As mentioned in the Chair's message, the Commission has evolved considerably and the increase in expenditures is due to a number of activities which include the significant costs associated with the Transmission Inquiry, which were not originally anticipated; the direction from the Court of Appeal to assess the adequacy of First Nations consultations in proceedings before the Commission; appointment and ongoing work with the Western Electricity Coordinating Council in the administration of the approved Reliability Standards program in BC; and unanticipated cost increases to both information technology and occupancy. While the Commission exceeded its established budget, full costs were recovered leaving the Commission in good standing for the 2010/2011 fiscal year.

2009/2010 EXPENDITURES



DECISIONS, REASONS FOR DECISION AND NEGOTIATED SETTLEMENTS

Summary of Decisions, Reasons for Decision and Negotiated
Settlements issued in 2009/2010

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

2007 Rate Design Application for Reconsideration of Order G-138-08 Commission Determination/Order G-41-09

On September 25, 2008 the Commission issued Order G-138-08 amending Directive 19 in the October 26, 2007 Rate Design Decision which "instructed BC Hydro to commence meaningful stakeholder engagement with its [Large General Service] customers to develop and file with the Commission an application for a rate structure or structures that encourage conservation without unduly benefiting or harming any of its customers in that class. Directive 19 set out that such a rate structure or structures should be in place by April 1, 2009 with a two-year phase-in if necessary." Order G-138-08 directed BC Hydro to file its Large General Service Rate Design application by June 30, 2009.

BC Hydro filed an application for reconsideration of Order G-138-08 on April 8, 2009 requesting deferral of the filing date of the LGS rate application to no later than October 16, 2009 indicating that the final round of customer consultation would not be completed in time for the June 30, 2009 submission date.

The Reconsideration Application proceeded directly to Phase 2 of the Commission's reconsideration process and submissions on BC Hydro's Application were received from six Interveners; BC Hydro's reply was filed on April 21, 2009. The Commission subsequently issued Order G-41-09, which varied Directive 1 of Order G-138-08 so that the filing date of the LGS rate application became October 16, 2009.

Joint Industry Electricity Steering Committee Reconsideration of BC Hydro's F2009 and F2010 Revenue Requirements Reasons for Decision/Order G-46-09

On March 12, 2009, the Commission issued its decision and Order G-16-09 on BC Hydro's F2009 and F2010 Revenue Requirements Application.

The Joint Industry Electricity Steering Committee [JIESC] subsequently applied for a reconsideration of the following two issues:

- [1] To reverse the part of the decision allowing BC Hydro full recovery of its proposed operating costs in F2009; and
- [2] To clarify or, if necessary, revise the accounting treatment of amortization of DSM expenditures in the decision.

The JIESC requested to reverse part of the March 2009 decision allowing BC Hydro full recovery of its proposed operating costs proceeded to Phase 1 of the Commission's reconsideration process. Comments were solicited from Interveners on whether a reasonable basis existed to allow a reconsideration. Submissions were received from the Commercial Energy Consumers Association of British Columbia and BC Hydro, and the JIESC filed its reply to the submissions.

Following a review of the comments submitted by the Commercial Energy Consumers Association of British Columbia and BC Hydro and the reply comments of the JIESC, the Commission issued its Reasons for Decision denying the JIESC's Application for Reconsideration of the decision. The JIESC reconsideration request for the Commission to clarify or, if necessary, revise the accounting treatment of amortization of demand side management expenditures in the decision was also denied.

Amend Section 2.1 of Rate Schedule 3808 Power Purchase Agreement
Decision dated May 6, 2009/Order G-48-09

On June 24, 2008, FortisBC filed its Umbrella Agreement for Short-Term Firm Point to Point Transmission Service dated April 18, 2008 between FortisBC and the Corporation of the City of Nelson, and the Power Coordination Agreement dated May 14, 2008 between FortisBC and the City of Nelson.

On June 25, 2008, the Commission requested comments from BC Hydro on the Umbrella Agreement and Power Coordination Agreement (collectively, the Nelson Agreements) filed by FortisBC.

On September 16, 2009, BC Hydro concurrently filed an application under subsections 58(1) and (2) of the Utilities Commission Act for approval to amend section 2.1 of the RS 3808 Power Purchase Agreement to clarify that electricity purchased by FortisBC under the Power Purchase Agreement cannot be sold to FortisBC customers to replace electricity to be sold by those customers.

DECISIONS, REASONS FOR DECISION AND NEGOTIATED SETTLEMENTS

BC Hydro and FortisBC both filed further submissions to the Commission stating that the only application that had been filed was with regard to BC Hydro's requested amendments to section 2.1 of the Power Purchase Agreement, any Commission review of the Nelson Agreements should be done in a separate process.

On October 2, 2008, Commission Order G-148-09 established a written public hearing process for review of the Application. The written hearing concluded on February 15, 2009. After reviewing all the evidence, the Commission issued its decision on May 6, 2009 approving the Application subject to directives, orders or qualifications contained within the decision.

2008 Long-Term Acquisition Plan Expenditure Request for Mica Units 5 and 6 Reasons for Decision/Order G-69-09

On June 12, 2008, BC Hydro filed its 2008 Long-Term Acquisition Plan with the Commission for review. The LTAP is a business planning tool that compares long-term future load requirements to existing and committed resources available to meet that load, and evaluates additional resources required to meet future load. As part of that application, BC Hydro requested an Order approving the expenditure of \$30 million in fiscal years 2009, 2010 and 2011 to undertake and complete the definition phase work for Mica Units 5 and 6.

The Commission held LTAP procedural conferences on September 9, 2008 and November 28, 2008, during which parties discussed whether arguments regarding the Mica Units 5 and 6 expenditure request would occur separately from the arguments for other matters. The Commission established that arguments concerning the Mica Units 5 and 6 definition phase expenditure request were to be heard in the main 2008 LTAP oral argument phase which commenced June 1, 2009.

Following a review of the evidence, the Commission determined that the \$30 million expenditure requested to undertake and complete the definition phase work for Mica Units 5 and 6 is in the public interest.

2008 Long-Term Acquisition Plan Expenditure Request for the Fort Nelson Generating Station Upgrade Reasons for Decision/Order G-75-09

After the June 12, 2008 filing of its 2008 LTAP with the Commission, BC Hydro, by letter dated October 24, 2008, filed an update to the evidentiary record related to Fort Nelson and requested an Order approving expenditures of \$140.1 million in fiscal years 2009 to 2012 to complete definition phase work and to implement the Fort Nelson Generating Upgrade Project Case 3.2.

Commission Order G-178-08 dated November 28, 2008 amended the BC Hydro 2008 LTAP regulatory timetable and established that the Fort Nelson Generating Station Upgrade Project definition and implementation phase expenditures request would remain part of the 2008 LTAP evidentiary and argument phases. The oral hearing commenced on February 19, 2009 and ended on March 12, 2009. BC Hydro filed its Argument on April 9, 2009; Interveners filed their Arguments on April 27, 2009; and BC Hydro filed its Reply on May 13, 2009. In Reply, BC Hydro submitted that the Fort Nelson Generating Upgrade Project expenditure request is supported by the Joint Industry Electricity Steering Committee, Commercial Energy Consumers of British Columbia and the Independent Power Producers of British Columbia and that no intervenor opposed this expenditure request.

Following a review of the evidence on the expenditures requested, the Commission determined, subject to conditions, that the \$140.1 million expenditures to complete the definition and implementation phases of the Fort Nelson Generating Station Upgrade Project are in the public interest.

2008 Long-Term Acquisition Plan
Decision dated July 27, 2009/Order G-91-09

The 2008 LTAP submitted to the Commission on June 12, 2008 was made up of many constituent parts. The LTAP included BC Hydro's analysis and conclusions of future natural gas prices, electricity prices, greenhouse gas prices, renewable energy credits, a demand side management plan, and a 20-year annual load forecast. BC Hydro sought three primary reliefs: (1) that the 2008 LTAP is in the public interest; (2) that the seven expenditures totalling \$633.3 million are in the public interest; and (3) that the Contingency Resource Plans be approved. BC Hydro also sought various Commission endorsements. The application was reviewed by an oral public hearing process.

In its July 27, 2009 decision, the Commission accepted BC Hydro's 2008 Load Forecasts and its price forecasts for natural gas, electricity greenhouse gas and renewable energy credits for the purposes of the 2008 LTAP. The Commission endorsed BC Hydro reliance on Burrard Thermal for planning purposes for 900 MW of capacity and the clean or renewable eligibility of the 2008 Clean Power Call. The Commission declined to endorse BC Hydro reliance on Burrard Thermal for planning purposes for 3,000 GWh/year for the purposes of the 2008 LTAP and BC Hydro's proposed target volume of the Clean Power Call. Finally, the Commission rejected BC Hydro's Demand Side Management Plan.

In the decision, the Commission rejected the 2008 LTAP as a whole because it did not approve or endorse many substantial elements. The Commission required BC Hydro, in its next LTAP, to present its electricity supply obligations and its plan for acquiring any supply-side resources for a minimum period of 20 years and for maintaining accordance with the self-sufficiency criterion of section 3 of Special Direction 10.

**Reconsideration of Order G-91-09 in the 2008 Long-Term Acquisition Plan
Reasons for Decision/Order G-150-09**

The Commission issued its decision and Order G-91-09 on July 27, 2009 with respect to BC Hydro's 2008 Long-Term Acquisition Plan. By letter and Application dated October 7, 2009, BC Hydro requested reconsideration and variance of condition 7 of Order G-91-09, which directed BC Hydro to comply with all other directives in the decision and more specifically requested a variation of directives 32 and 45. In addition, it requested clarification on how it was to treat the 400 MW market reliance.

On October 13, 2009, the Commission issued Letter L-92-09 in which it determined that the Reconsideration Application should proceed directly to Phase 2 of the reconsideration process. Submissions were received from 11 Interveners and BC Hydro filed its reply submission on November 4, 2009.

In its December 3, 2009 Reasons for Decision, the Commission determined that BC Hydro's two requests for variance and one request for clarification of the Decision were to be dealt with as follows:

- The filing date for BC Hydro's next LTAP was extended to on or before June 30, 2011;
- Directive 45 was varied to find that a determination as to whether or not a Voltage Optimization program should be classified as a demand side management program can and should be made only on a case-specific basis. BC Hydro was encouraged to bring forward a Major Threshold Project application for its proposed Voltage and Var Optimization/Voltage Optimization Program so that it could be appropriately reviewed and a determination made;
- The words "and 400 MW of capacity" were to be added after "2,500 GWh/year" with respect to BC Hydro's reliance on a market allowance to meet self-sufficiency criteria; and
- A new directive (Directive 47) was added to provide that the Commission Panel confirmed that the 400 MW market reliance cannot be relied on for planning purposes after 2015 as a result of section 3(d) of Special Direction 10.

**Gordon M. Shrum Units 1 to 5 Turbine Replacement Project
Reasons for Decision/Order G-1-10**

On August 5, 2009 BC Hydro filed an application seeking acceptance of: i) a schedule of capital expenditures in the amount of \$262.0 million BC Hydro anticipates making in respect of the Gordon M. Shrum Units 1 to 5 Turbine Replacement Project, and ii) a determination that the expenditures is in the public interest.

BC Hydro stated that Gordon M. Shrum is an essential part of BC Hydro's generating system, with a current capacity of 2,730 megawatts, and accounts for about one quarter of BC Hydro's generating capability. There are ten generating units within Gordon M. Shrum. The Project involves replacing the Units 1 to 5 turbines. Specifically, this includes designing and manufacturing new turbine runners, wicket gates, wicket gate operating mechanisms and head covers and overhauling the remaining turbine components.

The application was reviewed by a written public hearing and the Commission issued its Reasons for Decision on January 5, 2010. The Commission Panel determined the Project to be in the public interest, and accepted the capital expenditure schedule having a Project Expected Cost estimate of \$262.0 million.

**Acquisition from Teck Metals Ltd. of an Undivided One-Third Interest in the Waneta Dam and Associated Assets
Order G-12-10 dated February 3, 2010
Reasons for Decision dated March 12, 2010**

On June 17, 2009 BC Hydro entered into a non-binding master term sheet with Teck Metals Ltd. and Teck Resources Limited that contemplates the sale and purchase of an undivided one-third interest in the Waneta Dam on the Pend d'Oreille River and associated assets. BC Hydro's July 6, 2009 application requested acceptance by the Commission that proceeding with the purchase is in the public interest.

The Application was reviewed through a written public hearing, and final arguments, replies and sur-replies were filed by BC Hydro and Interveners during the period December 9, 2009 and January 6, 2010. On February 3, 2010, the Commission issued Order G-12-10 setting out its determinations; the Commission Panel's Reasons were issued on March 12, 2010.

The Commission made the following determinations:

1. The expenditure schedule contained in the filing, consisting of an \$825 million payment to Teck Metals Ltd., Teck Resources Limited or Teck American Limited to acquire a one-third interest in the Waneta Assets, plus associated transaction costs currently estimated at \$25 million, is in the public interest and accepted.
2. Subject to some conditions, the Commission accepted that it is in the public interest for BC Hydro to enter into the Co-Ownership and Operating Agreement.

DECISIONS, REASONS FOR DECISION AND NEGOTIATED SETTLEMENTS

3. BC Hydro is to file a fully executed Co-Ownership and Operating Agreement that is substantially like the draft agreement within 60 days of the closure of the Waneta Transaction, and is to file all amendments to the agreement in a timely manner.
4. Expenditures made by BC Hydro under the Co-ownership and Operating Agreement that BC Hydro cannot veto, or cannot refer to an independent third party referee, or which the referee determines BC Hydro is required to make, will be deemed to be in the public interest. BC Hydro shall ensure that other expenditures under the Co-ownership and Operating Agreement are in the public interest. Such other expenditures may be subject to a prudency review by the Commission.

Mica Gas Insulated Switchgear Project **Decision dated March 16, 2010/Order G-38-10**

On August 5, 2009 BC Hydro filed its application for its Mica Dam and Generating Station (Mica, Mica GS) 500 kilovolt (kV) Gas Insulated Switchgear Project requesting approval for expenditures to complete the Project at an Expected Cost of \$180.6 million and an Authorized Cost of \$200.2 million. The Project encompasses the replacement of all the existing gas insulated switchgear with modern technology, except for the recently replaced circuit breakers in the at-grade switchgear building. As well, it includes the installation of gas insulated switchgear in Lead Shaft 3 – an unused tunnel of the three from the below-ground generating units to the surface building that is in place as provision for the future addition of generating Units 5 and 6 to the existing Units 1 through 4. Installation of gas insulated switchgear in Lead Shaft 3 requires an extension of that existing switchgear building as a part of the Project, since Lead Shaft 3 does not presently terminate inside that building.

A written public hearing was established to review the Application and the filing of evidence and submissions was completed when BC Hydro filed its Reply Submission on December 3, 2009. The Commission Panel issued its decision on March 16, 2010, wherein the Panel determined that the Project was not in the public interest and ordered that the capital expenditure schedule having an expected cost estimate of \$180.6 million was not accepted.

Commissioner Vivian dissented the finding that Phase 9 of the Project was not in the public interest and that such a finding was sufficient to reject the Project in whole; as well as the determination not to reach any conclusion with respect to the adequacy of consultation with First Nations in respect of the Project.

Southern St'at'imc Electrification Project
Certificate of Public Convenience and Necessity
Reasons for Decision/Order G-58-10

On December 1, 2009 BC Hydro filed an application on behalf of BC Hydro and BCTC, for acceptance of a Project pursuant to sections 44.2(3)(a) and 58 to 61 of the Utilities Commission Act and the Remote Communities Regulation. The Project proposed to provide electricity service under the Program to the Southern St'at'imc Communities. The Southern St'at'imc Communities are located on reserve land in the Lillooet River Valley, are listed in Amendment 35/2009 to the Remote Community Regulation and are presently served by their own electrical distribution systems supplied by diesel generation and funded by Indian and Northern Affairs Canada.

Key considerations throughout the Project application were as follows: Project qualification for the Remote Community Electrification Program; source of power; grid connection alternatives; adequacy of First Nations consultation; appropriate zone rates and Project costs.

In its decision, the Commission Panel found that the Project qualifies for the Remote Communities Electrification Program. The Commission supports a grid connection and the connection recommendation. First Nations consultation was found to be adequate. Therefore, the Commission determines that the \$12.1 million capital expenditures that BC Hydro and BCTC anticipate making for the completion of the Southern St'at'imc Communities Project are in the public interest. Zone 1 rates and terms and conditions under the BC Hydro Electric Tariff will also apply in the Southern St'at'imc Communities.

Toad River Electrification Project
Certificate of Public Convenience and Necessity
Reasons for Decision/Order C-4-09

On June 19, 2009 BC Hydro submitted an Application for a Certificate of Public Convenience and Necessity for its Toad River Electrification Project. In the Application, BC Hydro applied for orders which grant a CPCN to serve the community of Toad River and for electricity tariff amendments to have Toad River listed as a Rate Zone II community. BC Hydro states that the Application for the community of Toad River is consistent with the 2007 Energy Plan, Electricity Policy Actions No. 27 and No. 28, and BC Hydro's 20-year Rural Community Electrification Program Plan.

On June 25, 2007 the BC Government enacted the Remote Communities Regulation and issued Special Direction No. 10 which directs the Commission to ensure that BC Hydro makes available to customers in remote communities the same rates and services it makes available in the Non-Integrated Areas.

The Application proceeded by way of a written hearing process. The Commission reviewed the Application, comments from Interveners involved in F2009-2010 Revenue Requirements, the Liard First Nation and granted a CPCN for a diesel generation plant to serve Toad River and to take over the distribution system in Toad River currently owned by the Northern Rockies Regional Municipality.

BRITISH COLUMBIA TRANSMISSION CORPORATION

Determination of Reliability Standards for Adoption in British Columbia Order G-67-09 dated June 8, 2009

On March 27, 2009 BCTC filed an assessment report assessing 103 reliability standards developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council. The filing was made in accordance with Ministerial Order M 039 dated February 22, 2009, which established the Mandatory Reliability Standards Regulation that described the parties that are subject to reliability standards adopted under the Utilities Commission Act. The Commission has exclusive jurisdiction to determine whether a reliability standard, as defined in the Act, is in the public interest and should be adopted in British Columbia.

A written process was established to review the reliability standards, the Assessment Report was posted to the Commission's web site, and BCTC was directed to publish a Notice of Assessment Report and Process for Public Comments. By letter dated May 4, 2009, BC Hydro submitted its comments on the Assessment Report; no other comments on the reliability standards assessed in the Assessment Report were received by the Commission.

The Commission reviewed and considered the Assessment Report and the comments received and determined that the 103 reliability standards be adopted in the form included in Appendix B to BCTC's Assessment Report effective June 8, 2009. The *NERC Glossary of Terms Used in Reliability Standards* and the *NERC Functional Model*, Version 3, were also adopted.

Transmission System Capital Plan F2010 and F2011 Reasons for Decision/Order G-87-09

On November 21, 2008 BCTC filed its latest Transmission System Capital Plan F2010 and F2011 requesting approval for \$324.7 million in capital project funding including Emergency, Third Party funded projects and Third Party requested projects. This is broken into three categories: Growth Capital projects, Sustaining Capital projects and BCTC Capital projects. Growth Project amounts reflect the BCTC portion of joint projects with BC Hydro. The

projects in this category require an additional \$88.9 million for Substation Distribution Assets that, under the Master Agreement between BC Hydro and BCTC, will remain with BC Hydro.

BCTC sought the following orders to be issued by the Commission:

- That the proposed projects and expenditures for approval in Growth, Sustaining and BCTC Capital portfolios are in the public interest as well as the emergency capital expenditures for F2008 and F2009.
- That BCTC's F2010 Capital Plan meets the requirements of section 45(6) of the Utilities Commission Act.
- That BCTC is relieved of certain Commission Directives under sections 88(2) and/or 99 of the Utilities Commission Act.

The Application was reviewed through a written public hearing process that took place during the period of January to March 2009. The written argument phase of the proceeding was completed when BCTC filed its Reply on April 1, 2009.

The Commission's decision, dated July 13, 2009, generally accepted the Growth Capital expenditures, the Sustaining Capital expenditures, and BCTC's Capital Expenditures as set out in the decision. The decision rejected certain Emergency capital expenditures for F2008, F2009 and F2010 and third party requested projects that are third party funded. Further, it rejected certain specified Growth Capital expenditures and Sustaining Capital expenditures but allowed BCTC to re-apply for approval, and it rejected a specific Capital expenditure and an exceptional project. The Commission also denied BCTC the relief it requested from some previous Commission directives.

**Amendment to the BCTC Open Access Transmission Tariff and
A Complaint by TransCanada Energy Ltd. regarding BCTC's Firm Transmission Sales to Alberta
Open Access Transmission Tariff Decision/Order G-102-09
TransCanada Complaint Decision/Order G-103-09**

On June 3, 2008 BCTC applied to the Commission to suspend the release for sale of additional Firm Available Transfer Capacity on the British Columbia to Alberta transmission interconnection path and to suspend the Facilities Study relating to requests for additional service on the BCTC transmission system. Commission Order G-110-08 granted BCTC's application and directed it to address certain issues raised in that application in the context of BCTC's next Open Access Transmission Tariff (BCTC Tariff) Application or Rate Design review, and to provide a tariff provision to address the issues.

The BCTC Tariff includes the rates, terms, and conditions of the non-discriminatory, open access transmission service offered by BCTC.

DECISIONS, REASONS FOR DECISION AND NEGOTIATED SETTLEMENTS

On October 9, 2008 TransCanada Energy Ltd. filed a complaint with the Commission against BCTC's decision in December 2007 to release additional Long-Term Firm Point to Point transmission capacity for sale on the BC to Alberta transmission path.

On November 21, 2008 BCTC filed its application to amend the BCTC Tariff and stated that the Application included its response to the TransCanada Complaint.

A procedural conference was held on January 8, 2009 to address procedural matters relating to the Open Access Transmission Tariff Amendment Application and the TransCanada Complaint. Following the conference, the Commission ordered that BCTC's Application to amend its Tariff, except the parts dealing with TransCanada's Complaint, would be reviewed through a written hearing process. The Complaint and BCTC's response would be reviewed through an oral hearing.

Upon completion of the written and oral hearings, the Commission Panel approved the BCTC Open Access Transmission Tariff Amendment Application, except as indicated in its decision. In a separate decision, the Commission Panel dismissed the TransCanada Complaint, but ordered BCTC to continue to suspend facilities studies on the BC to Alberta interconnection path and to amend its Tariff to limit sales of firm capacity on the path to 480 MW.

F2010-F2011 Transmission System Capital Plan Reapplication for Rejected Capital Expenditures Reasons for Decision/Order G-37-10

The Commission's July 13, 2009 decision on BCTC's November 21, 2008 F2010 and F2011 Transmission System Capital Plan rejected certain capital projects and programs due to the absence of any evidence which would enable the Commission to assess the adequacy of Crown consultation with First Nations on these projects and programs. Apart from a concern about the Identification of the Definition Phase funding level for two projects, the Commission expressed no other concerns about the rejected projects or programs. The Commission's decision also granted BCTC the right to re-apply for approval of the rejected expenditures.

BCTC filed its Re-application for Approval of Capital Expenditures, requesting the Commission accept certain of the Growth Capital and Sustaining Capital expenditures rejected by Order G-87-09 on November 20, 2009. The Re-application was reviewed by the same Commission Panel that heard the original F2010 and F2011 Transmission System Capital Plan.

In its Reasons for Decision dated March 9, 2010, the Commission Panel accepted, again in part, some of the Growth Capital and Sustaining Capital expenditures in the F2010 Capital Plan and rejected the following:

- Growth Capital expenditure for the Atchelitz Area Reinforcement Project Implementation Phase Funding.
- Certain Sustaining Capital expenditures in the Overhead Lines Life Extension Program.
- Certain Sustaining Capital expenditures in the Overhead Lines Risk Mitigation Program.
- Certain Sustaining Capital expenditures in the Overhead Lines Right-of-Way Sustainment Program.

Where Growth Capital or Sustaining Capital expenditures were rejected, BCTC may re-apply for approval for those expenditures once the evidence of First Nations consultation referred to in the Reasons for Decision becomes available.

**Reconsideration TransCanada Complaint (OATT) BC>AB Path
Commission Order G-103-09, as Confirmed by Letter L-95-09
Reasons for Decision/Order G-45-10**

On September 10, 2009 the Commission issued Order G-103-09 with Reasons for Decision, ruling on a complaint by TransCanada Energy Ltd. concerning transmission sales by BCTC on the British Columbia to Alberta transmission path (transmission path).

BC Hydro's November 26, 2009 application for reconsideration of Commission Order G-103-09, as confirmed in part by Letter L-95-09 sought reinstatement of 25 MW of Long Term Firm Point to Point capacity (firm capacity) on the transmission path which it lost as a result of Order G-103-09. In essence, Order G-103-09 required BCTC to cancel those contracts for firm capacity on the transmission path bearing a subject condition confirming those contracts were subject to a further order of the Commission. The purpose of cancelling the contracts was to reduce the amount of LTF PTP capacity offered for sale to 480 MW, which was the capacity offered prior to BCTC's decision to sell up to 785 MW of firm capacity starting on December 1, 2007. It subsequently came to light that the effect of cancelling those specific contracts, as opposed to reinstating the status quo immediately prior to December 1, 2007, was a reallocation of 25 MW of capacity from BC Hydro to Cargill Limited. This result was not intended by the Commission Panel.

DECISIONS, REASONS FOR DECISION AND NEGOTIATED SETTLEMENTS

BC Hydro's Reconsideration Application was supported by the three Intervener organizations representing the three major customer groups in the province: the British Columbia Old Age Pensioners' Organization et al. (BCOAPO), the Commercial Energy Consumers Association of British Columbia (CEC) and the Joint Industry Electricity Steering Committee (JIESC). The only party to oppose the Reconsideration Application was Cargill, the beneficiary of the Order.

On January 8, 2010 the Commission Panel determined that it was appropriate for the Reconsideration Application to proceed directly to Phase 2 of the reconsideration process, which involves a reconsideration on merits. The Commission Panel agreed with BC Hydro that the implementation mechanism (by which BC Hydro lost 25 MW of capacity which it held prior to December 1, 2007 to Cargill) was not adequately canvassed in the original proceeding and that the result of that implementation mechanism was never addressed prior to the Reconsideration Application. The Commission Panel therefore requested that BCTC file additional evidence to explain, among other things, the life cycle of each of the Service Agreements, which were in place prior to December 1, 2007 and the contract rollover process.

Following the submission of the additional evidence on February 1, 2010, submissions were received from BC Hydro, BCOAPO, the CEC, and the JIESC, supporting BC Hydro. Cargill opposed BC Hydro's request for relief.

The Commission Panel granted the Reconsideration Application and found that the effect of Order G-103-09 was to unfairly deprive BC Hydro of 25 MW of capacity while at the same time granting a windfall to Cargill. The Panel found that although Cargill's Service Agreement did not bear the formal condition confirming that its contract was subject to a further order of the Commission, it did have actual notice of this fact, both by way of a cover letter from BCTC accompanying its Service Agreement and from the express provisions of the Open Access Transmission Tariff. The Commission Panel further found that the notice provided by the condition was redundant in any event given its general rate-setting powers provided by the Utilities Commission Act. In the Panel's view, the inequity to BC Hydro from the loss of its capacity was greater than the marginal benefit of the additional transparency provided by the inclusion of the subject clause on certain contracts.

Order G-103-09 was varied so that all customers with firm service on the transmission path retain the same total amount of service capacity (MW) that they had prior to the sale of the 305 MW of additional capacity commencing in December 2007.

FORTISBC INC.

Net Metering Rate Schedule 95
Reasons for Decision/ Order G-92-09

On April 17, 2009 FortisBC submitted its Net Metering Rate Schedule 95 and resulting revisions to the FortisBC Electric Tariff Index and Rate Schedule 80 for Commission approval. Net Metering is a metering and billing practice that allows for the flow of electricity both to and from the customer through a single, bi-directional meter. With Net Metering, consumers with small, privately owned generators can efficiently offset part or all of their own electrical requirements by utilizing their own generation.

A written hearing was established to review the Application [Order G-43-09] and the regulatory process was conducted from May 22, 2009 to July 6, 2009. On July 30, 2009 the Commission issued its Reasons for Decision approving the FortisBC Net Metering program as proposed in the Application with some modifications.

2010 Revenue Requirements
Negotiated Settlement/Order G-162-09

Under the terms of the 2006 Revenue Requirements Settlement Agreement [Order G-58-06] and the Performance Based Regulation Settlement for the years 2007, 2008 and potentially 2009 (the PBR Settlement), FortisBC is required to hold an Annual Review, Workshop and Negotiated Settlement Process each November with a goal of achieving firm rates by December 1st for the following year. The Annual Review compares the Company's actual performance for the recently completed year to the approved targets for the Performance Standards to determine whether the Company is entitled to an incentive payment. The Revenue Requirements Workshop is to focus on future test periods and the NSP is conducted to establish rates for the following year. The Commission approved an extension of the 2007-2009 Performance-Based Rate Plan for the years 2009-2011 [Order G-193-08].

FortisBC filed its Preliminary 2010 Revenue Requirements on October 1, 2009, which sought a 4.6 percent general rate increase to be effective January 1, 2010. The 2010 Revenue Requirements Update was filed on November 2, 2009, which incorporated financial results and forecasts as of September 30, 2009, including financial Performance Standards for the period October 1, 2008 to September 30, 2009, and reduced the general rate increase sought to 4.0 percent.

DECISIONS, REASONS FOR DECISION AND NEGOTIATED SETTLEMENTS

Following the Annual Review and the 2010 Revenue Requirements Settlement discussions, a proposed Settlement Agreement and Letters of Support, which resulted in a general rate increase of 3.5 percent effective January 1, 2010, was circulated to the participants and registered Interveners. No comments were received from any registered Interveners who had not participated in the Settlement negotiations.

On December 18, 2009, the Commission approved the Settlement Agreement and the Terms of Settlement along with financial schedules showing the effect of changes arising from the negotiated settlement.

Revised Code of Conduct and Transfer Pricing Policy Brilliant Expansion Subcontractor Agreement Reasons for Decision/Order G-5-10A

On March 31, 2009 FortisBC filed its Revised Code of Conduct and Transfer Pricing Policy with the Commission in compliance with Order G-199-08, which granted interim approval of the Subcontractor Agreement between FortisBC and Fortis Pacific Holdings Inc. The Revised Code of Conduct will govern the relationships between FortisBC and its Non-Regulated Businesses; these are the affiliates of FortisBC that are not regulated by the Commission or divisions of the utility offering unregulated products and services. The revised code replaces FortisBC's Code of Conduct dated May 25, 2008.

The Revised Transfer Pricing Policy updates FortisBC's existing policy with respect to the appropriate rates to be applied to transactions between FortisBC and its Non-Regulated Businesses. The Application further addresses inter-corporate relationships between FortisBC and Terasen Gas Inc., another regulated affiliated entity.

In addition, pursuant to Commission Order G-199-08, the Application seeks final approval of the Subcontractor Agreement between FortisBC and Fortis Pacific Holdings Inc. made May 31, 2008, in connection with the ultimate supply of services by FortisBC to Brilliant Expansion Power Corporation.

The applications were reviewed through a written hearing process and the Commission's Reasons for Decision were issued on January 12, 2010, approving the Revised Code of Conduct and Transfer Pricing Policy, and the May 31, 2008 Subcontractor Agreement between Fortis Pacific and FortisBC for the supply of FortisBC resources to Brilliant Expansion Power Corporation. The interim rates under the Subcontractor Agreement were also confirmed as permanent, subject to certain adjustments made by the Commission.

PACIFIC NORTHERN GAS LTD.

**2009 Revenue Requirements
PNG-West Service Area
Settlement Agreement/Order G-39-09**

PNG-West filed its 2009 Revenue Requirements application proposing to increase delivery rates to all customers, except West Fraser-Kitimat, as a result of increases in cost of service and decreased deliveries to most customer classes. West Fraser-Kitimat delivery rates do not increase in light of a contract in place that provides for fixed delivery rates over the term of the contract.

PNG's 2009 revenue requirements were reduced by \$5.5 million by the amortization of the Methanex Corporation contract termination payment for the ten months to October 2009; the result of the closure of the Methanex methanol/ammonia complex in Kitimat in November 2005.

The Commission approved interim rates as requested in the Application, effective January 1, 2009, and the Application was reviewed through a negotiated settlement process. A Negotiated Settlement Agreement was reached among the participants and circulated to all registered Interveners and the Commission on April 15, 2009. No comments were received from the Interveners who had not participated in the settlement discussions.

The April 15, 2009 Negotiated Settlement Agreement for PNG's 2009 Revenue Requirements Application was approved by the Commission and PNG was directed to refund to customers the difference between permanent 2009 rates and the interim rates with interest in accordance with Commission Order G-182-08.

**2010-2011 Revenue Requirements
Interim Negotiated Settlement/Order G-33-10**

On October 2, 2009 PNG applied for approval of its PNG-West service area 2010 Revenue Requirements to increase delivery rates to all customers, except West Fraser-Kitimat, as a result of increases in cost of service and decreased deliveries to most customer classes. West Fraser-Kitimat delivery rates do not increase in view of a contract in place that provides for fixed delivery rates over the term of the contract. PNG's Application forecasts a 2010 revenue deficiency of approximately \$7.7 million comprised of a net increase in cost of service of \$7.5 million and a decrease in revenue margin of \$0.2 million.

In November 2005, the Methanex Corp. closed its methanol/ammonia complex in Kitimat, which resulted in an increase of \$5.5 million in PNG's 2010 cost of service, due to the amortization of the Methanex contract termination payment being completed in October 2009.

DECISIONS, REASONS FOR DECISION AND NEGOTIATED SETTLEMENTS

The Application requested approval to increase the delivery charge, on an interim basis, for residential service, small commercial service, and for Granisle propane service effective January 1, 2010. The Commission approved interim delivery rates for these categories.

The Application was reviewed through a Negotiated Settlement Process and an Interim Negotiated Settlement Agreement was reached among the participants. The agreement was circulated to all registered Interveners and the Commission on February 22, 2010. No comments were received from the Interveners who had not participated in the settlement discussions.

On March 4, 2010, the Commission approved the February 22, 2010 Interim Negotiated Settlement Agreement for PNG's 2010 Revenue Requirements Application. Some issues not covered by the agreement were to be issues at the upcoming hearing for PNG's July 16, 2009 Capital Structure and Equity Risk Premium Application. Following disposition of PNG's Capital Structure and Equity Risk Premium Application, the 2010 Revenue Requirements negotiations were to resume for the purpose of establishing permanent delivery rates for 2010.

PACIFIC NORTHERN GAS (N.E.) LTD.

2009 Revenue Requirements for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions Negotiated Settlement/Order G-40-09

PNG (N.E.)'s 2009 Revenue Requirements Application for its Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) Divisions proposed to amend rates on an interim and final basis, effective January 1, 2009.

The Commission approved interim rates at the level sought under the Application and the Application was reviewed through a negotiated settlement process. A Negotiated Settlement Agreement was reached among the participants and circulated to all Registered Interveners and the Commission on April 15, 2009. No comments were received from the Interveners who had not participated in the settlement discussions.

The April 15, 2009 Negotiated Settlement Agreement for PNG (N.E.)'s 2009 Revenue Requirements Application was approved by the Commission, and the utility was directed to refund to customers the difference between permanent 2009 rates and the interim rates, with interest, in accordance with Commission Order G-183-08.

**2010-2011 Revenue Requirements
Interim Negotiated Settlement/Order G-34-10**

On October 5, 2009, PNG (N.E.) Fort St. John/Dawson Creek and Tumbler Ridge Divisions applied for approval of its 2010 Revenue Requirements Application to amend its rates on an interim basis, effective January 1, 2010, to reflect the impact of changes to PNG (N.E.)'s capital structure and rate of return as set forth in the Capital Structure and Equity Risk Premium (CAP/ROE) Application and recommended that rates set by this Application remain interim pending the Commission's disposition of the CAP/ROE Application. The Capital Structure and Equity Risk Premium Application sought a common equity thickness for PNG (N.E.) of 42.5 percent and a rate of return on common equity set at 75 basis points above the Commission's low risk benchmark utility return on equity.

PNG (N.E.)'s Revenue Requirements Application requested approval to increase, on an interim basis, the delivery charges for residential service and small commercial service for each of the Fort St. John/Dawson Creek and Tumbler Ridge Divisions based on the common equity thickness and rate of return on common equity applied-for in the Capital Structure and Equity Risk Premium Application.

Interim delivery rates were established by the Commission, effective January 1, 2010, based on the existing common equity thickness of 36 percent and a rate of return on common equity set at the existing 40 basis points above the Commission's low risk benchmark utility return on equity.

The Application was reviewed through a negotiated settlement process and an Interim Negotiated Settlement Agreement was reached among the participants and circulated to all registered Interveners and the Commission on February 22, 2010.

On March 4, 2010, the Commission approved the February 22, 2010 Interim Negotiated Settlement Agreement for PNG (N.E.)'s 2010 Revenue Requirements Application. Final rates were to be calculated following the Commission's disposition PNG's Capital Structure and Equity Risk Premium proceeding and after the completion of PNG-West's 2010 final Revenue Requirements negotiations.

DECISIONS, REASONS FOR DECISION AND NEGOTIATED SETTLEMENTS

STARGAS UTILITIES LTD.

2009 Application to Alter Rates, Refinance and Gas Supply Contract Reasons for Decision/Order G-164-09

Stargas' July 29, 2009 application to alter rates, refinance and acceptance of a gas supply contract requested Commission approval to amortize various deferral accounts, increase the rates paid to Okanagan Funding Ltd., and change the method for recovering plant amortization. Stargas also requested expedited reviews of the refinancing and gas supply contract portions of the application to meet closing deadlines.

Following a review of the of the refinancing and gas supply contract portions of the application, the Commission issued Order G-116-09 dated September 29, 2009 approving the refinancing and Order E-13-09 dated October 22, 2009, approving the New Gas Supply Contract.

Stargas amended its application on October 1, 2009 and requested approval to decrease the residential and commercial delivery rates, residential commodity rates, and commercial commodity rates effective November 1, 2009. The Commission approved, on an interim and refundable basis, a \$0.90 GJ decrease in residential and commercial delivery rates, a \$4.05 per GJ decrease in residential commodity rates and a \$4.26 per GJ decrease in commercial commodity rates, effective November 1, 2009, and established a written hearing process to review the amended application. No interveners or interested parties registered with the Commission for this proceeding.

The Commission's Reasons for Decision regarding Stargas' application was issued on December 17, 2009, and approved the Stargas request to draw down the Gas Cost Variance Account credit balance in F2010. The Commission approved the Stargas requests to end the deferral of plant amortization and to amortize the balance of the previously deferred plant amortization and the accumulated interest over ten years. The Commission limited Okanagan Funding Ltd. hourly rates for accounting, administrative and executive services provided to Stargas, and directed Stargas to pay the full F2010 dividend on its preferred shares. The Commission denied Stargas' request to amortize \$135,887 of accumulated unpaid dividends on Stargas' preferred shares into its revenue requirement over ten years. The Commission approved a \$0.90 per GJ decrease in residential and commercial delivery rates, a \$4.43 per GJ decrease in residential commodity rates, and the \$4.64 per GJ decrease in commercial commodity rates, effective November 1, 2009.

TERASEN GAS INC.

Customer Care Enhancement Project
CPCN Order C-1-10 / Order G-23-10 dated February 16, 2010

On June 2, 2009 Terasen Gas filed an application for a Certificate of Public Convenience and Necessity for its Customer Care Enhancement Project. The Project involves returning key components of previously outsourced customer care services (customer contact, meter reading, billing, payment processing, contract management, collections, and customer information services system support) and the implementation of a new customer information system to Terasen Gas. The utility also applied for the creation of a rate base deferral account for the purpose of recovering costs through customer rates.

The Application was reviewed through a written hearing process and on February 16, 2010, the Commission issued Order G-23-10 in which it determined that it is not in the public interest for Terasen Gas to implement the Project at a total cost of \$115.5 million. Although the Commission denied the Application as filed, it issued a Certificate provided Terasen Gas accepted a term sharing equally between Terasen Gas and its ratepayers any cost over-runs or savings more than ten percent above or below the cost estimate.

On February 26, 2010 Terasen Gas filed a statement confirming its acceptance of the above noted term and the Commission subsequently issued Certificate of Public Convenience and Necessity Order C-1-10 dated February 26, 2010, with reasons to follow.

Tilbury Property Purchase
Certificate of Public Convenience and Necessity
Reasons for Decision/Order G-28-10/G-68-10

Terasen Gas applied for a Certificate of Public Convenience and Necessity for the purposes of purchasing the property known as the Northwest Hardwoods Site (the Property) located adjacent to Terasen's Tilbury Island Liquefied Natural Gas Facility. The Property will be incorporated into the Tilbury Liquefied Natural Gas Facility operations for the purposes of preserving Terasen's ability to continue operating in compliance with the Canadian Standards Association's mandatory standard governing the operation of the facility. Terasen Gas has also entered into a Contract of Purchase and Sale (the Contract) to acquire the Property, conditional upon (among other things) obtaining Commission approval by March 11, 2010.

The Application was reviewed through a written public hearing and on February 23, 2010, the Commission issued Order G-28-10 with Reasons for Decision granting a CPCN to Terasen Gas for the Tilbury Property Purchase

DECISIONS, REASONS FOR DECISION AND NEGOTIATED SETTLEMENTS

subject to certain conditions. Terasen Gas was to file a written confirmation of its acceptance of the above conditions within 10 working days of the Order, failing which the application would be refused.

In a letter dated March 9, 2010, Terasen Gas advised that it was unable to accept the existing conditions in the Order; however, the utility applied for reconsideration and variance of the Order. The original Contract of Purchase and Sale for the Property was amended to extend the date for obtaining Commission approval until April 23, 2010. The Reconsideration Application was also heard through a written comment process.

Following its review of the Reconsideration Application and related evidence the Commission Panel issued Order G-68-10, which rescinded some of the conditions in Order G-28-10 and substituted new conditions.

On April 14, 2010, Terasen Gas filed a letter accepting the conditions in Orders G-28-10/G-68-10. Certificate of Public Convenience and Necessity Order C-2-10 was subsequently issued on April 28, 2010.

2010 and 2011 Revenue Requirements/Delivery Rates Negotiated Settlement Agreement/G-141-09

Terasen Gas applied for approval of interim and permanent delivery rates representing an increase of 5.3 percent for 2010 and 4.1 percent for 2011, as well as tariff changes regarding Compression and Refueling and Transportation Services for Natural Gas Vehicles and economic models for evaluating biogas projects and alternative energy extensions for geo exchange, solar thermal and district energy systems to complement its core natural gas business.

The Application was reviewed through a negotiated settlement process. The November 13, 2009 Negotiated Settlement Agreement, together with the Letters of Support received from the participants, the Letter of Comment from Commission Staff and Terasen Gas' response to the Letter of Comment, was made public and circulated to the Commission Panel and registered interveners who did not participate in the NSP. No additional comments were received from the other Interveners.

On November 26, 2009, the Commission approved the November 13, 2009 Negotiated Settlement Agreement.

Customer Choice - 2009 Program Summary and Recommendations Reasons for Decision/Order A-3-10

Serving as a pilot program to assist in the implementation of the larger residential program, Terasen Gas implemented the commodity unbundling service for small and large commercial customers in 2004. Process changes and system development were completed allowing eligible customers to begin enrolling in the program

starting May 2004. Natural gas flowed to commercial customers who elected a gas marketer to provide the commodity on November 1, 2004.

The Essential Services Model (ESM) that underpinned the successful commercial introduction remained largely unchanged when the Customer Choice Program (Program) was subsequently introduced to residential customers in May 2007. The ESM is designed to meet the unique circumstances of the BC marketplace, and it mitigates gas marketer risk by absolving them of the commodity variance true-up responsibilities favoured in other jurisdictions. A number of small and large gas marketers participated in the 2007 launch of the Program.

Since the start of the Program, several information technology system enhancements have been implemented. Recent enhancements were recommended in a report and application submitted to the Commission on July 18, 2008. Terasen Gas recommended the implementation of these changes in four staged releases.

On April 23, 2009, the second Customer Choice Annual General Meeting was held to discuss the concerns and suggestions of interested parties, and to review both the communication activities planned for 2009 and 2010, as well as system enhancements that have taken place since 2008. Terasen Gas was requested by Commission staff to file a Report, the Customer Choice - 2009 Program Summary and Recommendations (the Application), which Terasen Gas filed on October 16, 2009.

The Application was reviewed through a written hearing process and on February 22, 2010, the Commission issued Order A-3-10 with Reasons for Decision. Gas Marketers were notified that where Code of Conduct changes are required, the changes will be included in a revised Code of Conduct to be released upon completion of the noted changes to the Third Party Verification script. The 2010 Customer Choice Annual General Meeting will be held on September 8, 2010.

TERASEN GAS INC./TERASEN GAS (VANCOUVER ISLAND) INC.

Energy Efficiency and Conservation Programs Application
Decision dated April 16, 2009/Order G-36-09

On May 28, 2008 Terasen Gas and TGVI filed an application for approval of various concepts and expenditures in support of an expanded energy efficiency and conservation strategy, and to capitalize incremental energy efficiency and conservation expenditures by charging the expenditures to a regulatory asset deferral account and amortising the balance over 20 years. By Order G-130-08 dated September 18, 2008, the Commission established a written hearing process to review the Application.

Following the written hearing, which concluded on December 5, 2008, the Commission accepted expenditures of \$31.1 million for the combined Residential Energy Efficiency and Commercial Energy Efficiency programs;

DECISIONS, REASONS FOR DECISION AND NEGOTIATED SETTLEMENTS

expenditures for programs or initiatives directed at fuel switching away from fossil fuels with a higher carbon content than that of natural gas; \$6.9 million for the Conservation Education Action and Outreach program; \$3 million for Joint Initiatives; and \$0.5 million for an updated Conservation Potential Review. The Commission accepted Terasen's proposal to include carbon tax reductions in computing benefit-cost analyses. The Commission further accepted Terasen's proposal for accountability mechanisms and directed Terasen to file an annual report on its EEC activities as described in the Commission's Decision.

The Commission approved the Total Resource Cost test as the appropriate test for cost effectiveness. The Commission also accepted Terasen Gas' proposed portfolio level approach based on achieving a portfolio Total Resource Cost test result of 1.0 or greater provided that components of the portfolio with a Total Resource Cost result of less than 1.0 were sufficiently justified.

The Commission rejected proposed expenditures of \$3 million for Innovative Technologies, Natural Gas Vehicles and Measurement and \$1.5 million for Trade Relations. The Commission further rejected Terasen's proposal to exclude the free rider factor from benefit-cost analyses as well as its proposal to attribute some of the savings from regulatory changes to energy efficiency and conservation programs.

The Commission directed Terasen Gas to commence the planning process for development of an Industrial energy efficiency and conservation program and file a report with the Commission within 90 days of the date of the decision.

TERASEN GAS INC./TERASEN GAS (VANCOUVER ISLAND) INC./TERASEN GAS (WHISTLER) INC.

Return on Equity and Capital Structure

Decision dated December 16, 2009 / Order G-158-09

On May 15, 2009 the Terasen Utilities filed an application requesting the elimination of the Automatic Adjustment Mechanism in the determination of its return on equity. Terasen Gas requested that its return on equity, which has been used as the benchmark return on equity for utilities in British Columbia, be determined in this proceeding instead. TGI and Terasen Whistler requested that the Commission continue to set their respective allowed return on equities with reference to the Benchmark return on equity by adding a utility specific risk premium of 70 basis points in the case of TGI and 50 basis points in the case of Terasen Whistler.

Terasen Gas also sought relief to have the revised return on equities be effective July 1, 2009; and that the common equity component of Terasen Gas' capital structure for rate-setting purposes from 35.01 percent to 40 percent be included in the setting of Terasen Gas' rates effective January 1, 2010.

The Application was reviewed by an oral hearing process and the Commission issued its decision on December 16, 2009.

In the decision, the Commission agreed with the Interveners that all risks cited by Terasen Utilities existed in 2005 (when its capital structure was last reviewed) with the exception of the climate change related risks and those related to First Nations. The Commission agreed with Terasen Utilities that Terasen Gas' business risk has increased since 2005 and that the additional risk suggests an equity ratio of 40 percent.

With regard to the return on equity sought by Terasen Gas, the Commission considered the range of approaches and estimates put forward by the expert witnesses from the applicant and the interveners. The Commission agreed with Terasen Utilities that all three approaches, namely: discounted cash flow, equity risk premium, and comparable earnings, should be taken into account. The Commission determined that the return on equity for Terasen Gas is 9.50 percent.

The Commission noted that the Automatic Adjustment Mechanism, if applied, would only provide 8.43 percent return on equity for Terasen Gas and therefore concluded that, given its determination of 9.5 percent return on equity as benchmark, the mechanism in its present configuration would not have provided a return on equity for Terasen Gas for 2010 that could meet the fair return standard. The Commission directed that the Automatic Adjustment Mechanism be eliminated and that Terasen Gas was to complete its study of alternative formulas and report to the Commission by December 31, 2010.

TERASEN GAS (VANCOUVER ISLAND) INC.

**2010 and 2011 Revenue Requirements, Rates, Cost of Service, Rate Design and
Revenue Deficiency Deferral Account Balance as at December 31, 2008
Negotiated Settlement Agreement/Order G-140-09**

On June 29, 2009, TGVI filed an application for approval of interim and permanent delivery rates requesting (a) no change in 2009 sales service rates and (b) a reduction in rates for firm transportation service, other than for those customers who have specified rates in their transportation service agreements, in the amount of 4.75 percent. TGVI also proposed that the rates established for 2010 should also remain in place for 2011.

The Application also requested interim and permanent approval of TGVI's forecast cost of service for 2010 and 2011, subject to the need to recover any Accumulated Revenue Deficiency after December 31, 2009 and any changes in TGVI's return on equity; and approval of the December 31, 2008 year-end balance in the Revenue Deficiency Deferral Account in the amount of \$7,149,210.

The Application was reviewed through a negotiated settlement process and on November 13, 2009, the Negotiated Settlement Agreement, together with the Letters of Support received from the participants in the negotiated settlement process, was made public and circulated to the Commission Panel and registered interveners who did

DECISIONS, REASONS FOR DECISION AND NEGOTIATED SETTLEMENTS

not participate in the settlement process. No comments were received from Interveners. On November 26, 2009, the Commission approved the Negotiated Settlement Agreement.

TERASEN GAS (WHISTLER) INC.

Amend its Schedule of Rates effective January 1, 2009 and for a Return on Equity and Capital Structure Decision dated April 7, 2009/Order G-35-09

On October 3, 2008, Terasen Whistler filed an application covering its 2009 Revenue Requirements, Return on Equity and Capital Structure and the resulting rate and tariff changes. Terasen Whistler filed amendments to its application on November 21, 2008, which addressed four cost of service related items (costs related to its conversion from propane to natural gas, overhead capitalization, income tax refund, and International Financial Reporting Standards costs, as well as two tariff-related matters).

Terasen Whistler's Application requested that its bundled variable rates be reduced; that its allowed return on equity be set at 75 basis points above the benchmark low-risk utility, and that its capital structure be set at 60 percent debt and 40 percent common equity. Terasen Whistler also requested approval of changes in certain accounting treatments and the continuation of certain deferral accounts, and it proposed to harmonize its system extension and customer connection policies with those of Terasen Gas and TGV, as it would be converted to a natural gas system.

Following a written hearing, the Commission generally approved Terasen Whistler's Amended Application, except where adjusted by the Commission, but did not approve the utility's requested permanent reduction to its total bundled variable rates.

UNIVERSAL ENERGY CORPORATION

Reconsideration of Commission Order G-157-08 Breach of Code of Conduct Reasons for Decision/Order A-5-09

On December 8, 2008 Universal filed a Request for Reconsideration of Commission Order G-157-08, dated October 24, 2008, which dealt with an August 28, 2008 complaint to the Commission from customers with respect to the alleged conduct of one of Universal's sales agents in the course of entering into a natural gas sales Agreement with the customer.

Universal requested a reconsideration of Order G-157-08 on the grounds that the Inquiry Officer made findings and recommendations in a manner that contravened the basic requirements of procedural fairness and that he exceeded the proper scope of his mandate.

The Commission allowed the request for reconsideration (Order G-201-08A dated December 22, 2008) and the request was reviewed through a written hearing. The Commission Panel considered the issues to be as follows:

1. Was the investigation undertaken by the Inquiry Officer conducted in accordance with the requirements for procedural fairness?
2. Did the evidence support the cancellation of the Agreement between Universal and the customers?
3. Was the proper scope of the Inquiry exceeded?

On April 24, 2009, the Commission issued Order A-5-09 with Reasons for Decision varying Order G-157-08 as follows:

1. Paragraph 1 of Order G-157-08, which accepted the findings and recommendations of the Inquiry Report, was varied and amended to accept only the findings made at pages 14 and 15 of the Inquiry Report relating to the timing for the expiry of the cancellation period and the recommendation to allow cancellation of the Agreement based on those findings.
2. Paragraph 2 of Order G-157-08, which cancelled the Agreement between Universal and the customer, was confirmed.
3. Paragraph 3 of Order G-157-08, which required the parties at the next Annual Review of the Code of Conduct to review the issues raised in the Inquiry Report to seek resolutions on any modifications of the Code of Conduct that the Commission should consider, was rescinded.
4. Paragraph 4 of Order G-157-08, awarding of costs against Universal, was rescinded.

APPENDICES

74	I	Staff List
75	II	Regulated Utilities
80	III	Natural Gas Marketers Licensed in 2009/2010
81	IV	Domestic Electricity Sales - 2009
82	V	Domestic Gas Sales - 2009
83	VI	Main Electric Transmission and Power Generating Facilities (Map)
84	VII	Natural Gas and Gas Liquids Utilities (Map)
85	VIII	Performance Indicators Hearing/Alternative Dispute Resolution Days (Fiscal 2009/2010) Customer Complaints and Inquiries (Fiscal 2009/2010) Gas Marketer Complaints/Disputes Staffing Levels Directives Issued Commission Expenditures and Cost of Regulation per Customer Cost of Energy Regulation per Equivalent Gigajoule of Energy Sold Cycle Times
95	IX	Summary of Commission Orders issued in 2009/2010
118	X	Standard Abbreviations & Acronyms
119	XI	Glossary of Terms
122	XII	Energy Conversion Factors

Appendices

74	I	Staff List
75	II	Regulated Utilities
80	III	Natural Gas Marketers Licensed in 2009/2010
81	IV	Domestic Electricity Sales - 2009
82	V	Domestic Gas Sales - 2009
83	VI	Main Electric Transmission and Power Generating Facilities (Map)
84	VII	Natural Gas and Gas Liquids Utilities (Map)
85	VIII	Performance Indicators Hearing/Alternative Dispute Resolution Days (Fiscal 2009/2010) Customer Complaints and Inquiries (Fiscal 2009/2010) Gas Marketer Complaints/Disputes Staffing Levels Directives Issued Commission Expenditures and Cost of Regulation per Customer Cost of Energy Regulation per Equivalent Gigawatt-hour of Energy Sold Cycle Times
95	IX	Summary of Commission Orders issued in 2009/2010
116	X	Standard Abbreviations & Acronyms
119	XI	Glossary of Terms
122	XII	Energy Conversion Factors

Appendices



STAFF LIST

Following is a list of the April 2010 Commission staff, their positions and departments:

OFFICE OF THE CHAIR AND FINANCIAL
ADMINISTRATION

Len Kelsey	Chair & Chief Executive Officer
Viki Vourlis	Manager of Finance, Human Resources, Administration, & Assistant to the Chair/CEO
Denise Goddard	Financial Assistant/ Administrative Clerk
Kim Brooks	Financial Assistant/ Administrative Clerk

RATES AND FINANCE

Philip Nakoneshny	Director
Suzanne Sue	Senior Financial Analyst
Claudia McMahon	Financial Analyst
Kristine Bienert	Financial Analyst
Yolanda Domingo	Financial Analyst

ENGINEERING AND ENERGY MARKETS

Brian Williston	Director
Robert Brownell	Senior Commodities Analyst
Don Flintoff	Senior Electrical Engineer
Mark Thomas	Senior Gas Engineer
Roy Bishop	Senior Electrical Engineer

TRANSMISSION INQUIRY

Jim Fraser	Director, Transmission Inquiry
-------------------	--------------------------------

INFORMATION SERVICES
GROUP

Erica Hamilton	Commission Secretary
Constance Smith	Assistant Commission Secretary
Jenelyn Torres	Customer Choice Administrator
Kristen Olsen	Customer Service Specialist
Alison Cormack	Information Services Officer
Yvonne Lapierre	Administrative Clerk
Daniela Guest	Administrative Clerk
Mark Hudson	Web Administrator
Kathy Grasty	Receptionist

STRATEGIC SERVICES

Doug Chong	Director
Eileen Cheng	Senior Economist
Tony Roberts	Senior Economist
Alison Richter	Regulatory Analyst, First Nations & Sustainability

REGULATED UTILITIES

CROWN-OWNED ELECTRIC UTILITIES**SERVICE AREA**

British Columbia Hydro and Power Authority
333 Dunsmuir Street
Vancouver, BC V6B 5R3
Email Contact: bchydroregulatorygroup@BCHydro.com

Lower Mainland, Vancouver Island,
Central and Northern BC and
East Kootenay Regions

British Columbia Transmission Corporation
Suite 1100, Four Bentall Centre
1055 Dunsmuir Street PO Box 49260
Vancouver, BC V7X 1V5
Email Contact: bctc.regulatory@bctc.com

BC Transmission and
Integrated Grid System

INVESTOR-OWNED ELECTRIC UTILITIES**SERVICE AREA**

Corix Multi Utility Services Inc.
[formerly Sun Rivers Services Corp.]
#1128 Burdette Street
Richmond, BC V6V 2Z3
Email Contact: glenn.lauffer@corix.com

Lot 152, CLSR Plan 78619
Kamloops IR No. 1

Hemlock Valley Electrical Services Limited
20955 Hemlock Valley Road,
Agassiz, BC V0M 1A1
Berezan Management Group
Email Contact: info@hemlockvalleyresort.com

Hemlock Valley

Silversmith Power & Light Corporation
Box 369
New Denver, BC V0G 1S0
Email Contact: silversmith@netidea.com

Sandon, BC

INVESTOR-OWNED ELECTRIC UTILITIES**SERVICE AREA**

FortisBC Inc.
P.O. Box 130
Trail, BC V1R 4L4
Email Contact: regulatory@fortisBC.com

West Kootenay and
Okanagan Regions of BC
Princeton, Osoyee Lake and
Moose Lake Areas

The Yukon Electrical Company Limited
100 - 1100 1st Avenue
Whitehorse, Yukon Territory Y1A 3T4
Facsimile Contact: (867) 668-3965

Lower Post

INVESTOR-OWNED NATURAL GAS OR PROPANE UTILITIES**SERVICE AREA**

Big White Gas Utility
P.O. Box 2039, Station "R"
Kelowna, BC V1X 4K5
Email Contact: mvalcourt@bigwhite.com

Big White Ski Resort

Cal-Gas Inc.
4255 - 64th Avenue S.E.
Calgary, Alberta T2C 2C8
Facsimile Contact: (403) 279-9098
Email Contact: jsereda@calgasinc.com

Canyon Ridge and Sonoma Pines

Corix Multi Utility Services Inc.
1128 Burdette Street
Richmond, BC V6V 2Z3
Email Contact: glenn.laufer@corix.com

Lot 152, CLSR Plan 78619
Kamloops IR No. 1, Panorama
and Sonoma Pines

Dockside Green Energy LLP
301-2659 Douglas Street
Victoria, BC, V8T4M3
Facsimile Contact: 250-360-1500

District Energy System, Victoria

INVESTOR-OWNED NATURAL GAS OR PROPANE UTILITIES

SERVICE AREA

Pacific Northern Gas Ltd.
950 - 1185 West Georgia Street
Vancouver, BC V6E 4E6
Email Contact: info@png.ca

Summit Lake to Prince Rupert and
Kitimat

Pacific Northern Gas (N.E.) Ltd.
950 - 1185 West Georgia Street
Vancouver, BC V6E 4E6
Email Contact: info@png.ca

Dawson Creek, Rolla, Pouce Coupe,
Tumbler Ridge, Fort St. John

Pacific Northern Gas Ltd.
950 - 1185 West Georgia Street
Vancouver, BC V6E 4E6
Email Contact: info@png.ca

Granisle (Propane Grid System)

Port Alice Gas Inc.
#101 - 4381 Dawson Street
Burnaby, BC V5C 4B4
Email Contact: david@portalicegas.com

Port Alice (Propane Grid System)

Stargas Utilities Ltd.
P.O. Box 3002
Silver Star Mountain, BC V1B 3M1
Email Contact: stargas@shaw.ca

Silver Star resort community

Sun Peaks Utilities Co., Ltd.
1280 Alpine Road
Sun Peaks, BC V0E 1Z1
Email Contact: utilities@sunpeaksresort.com

Resort area north of Kamloops

Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
Email Contact: regulatoryaffairs@terasengas.com

Lower Mainland, Fort Nelson, Central
and Northern Interior, the Kootenays
and the Okanagan

INVESTOR-OWNED NATURAL GAS OR PROPANE UTILITIES**SERVICE AREA**

Terasen Gas [Vancouver Island] Inc.
 16705 Fraser Highway
 Surrey, BC V4N 0E8
 Email: regulatory.affairs@terasengas.com

Sunshine Coast, Powell River, and
 Vancouver Island north to Campbell
 River, west to Port Alberni, and south to
 Victoria

Terasen Gas [Whistler] Inc.
 16705 Fraser Highway
 Surrey, BC V4N 0E8
 Email: regulatory.affairs@terasengas.com

Whistler (Propane Grid System)

INVESTOR-OWNED STEAM HEAT UTILITY**SERVICE AREA**

Central Heat Distribution Limited
 720 Beatty Street
 Vancouver, BC V6B 2M1
 Email Contact: CHDL@telus.net

Downtown Vancouver

REGULATED COMPANY**COMPULSORY AUTOMOBILE INSURANCE****SERVICE AREA**

Insurance Corporation of British Columbia
 Suite 517 - 151 West Esplanade
 North Vancouver, B.C. V7M 3H
 Email Contact: regaffairs@ICBC.com

Province of BC

MUNICIPALLY-OWNED ELECTRIC UTILITIES

SERVICE AREA

Municipally-owned electric utilities are not regulated under the Utilities Commission Act. Only the City of Nelson's electric utility with service outside of the Municipal boundaries is subject to regulation by the British Columbia Utilities Commission.

City of Grand Forks Box 220 Grand Forks, BC V0H 1H0	Grand Forks
City of Kelowna 1435 Water Street Kelowna, BC V1Y 1J4	Kelowna
City of Nelson (also known as Nelson Hydro) 502 Vernon Street Nelson, BC V1L 4E8	Nelson (urban and rural areas)
City of New Westminster 511 Royal Avenue New Westminster, BC V3L 1H9	New Westminster
City of Penticton 616 Okanagan Avenue East Penticton, BC V2A 3K6	Penticton
District of Summerland Box 159 Summerland, BC V0H 1Z0	Summerland

NATURAL GAS MARKETERS LICENCED IN 2009/2010

Licence No.	Gas Marketer
A-8-09	Access Gas Services Inc.
A-22-09A	Active Renewal Energy Marketing Ltd.
A-10-09	Altogas Energy Limited
A-13-09	Cascadia Energy Ltd.
A-17-09	Connect Energy Partnership
A-23-09A	Direct Energy Marketing Limited / Direct Energy Business Services
A-7-09	Energy Savings (B.C.) Limited Partnership
A-12-09	Firefly Energy
A-14-09A	Just Energy (B.C.) Limited Partnership Doing Business as Commerce Energy (Commercial Customers) Just Energy (B.C.) Limited Partnership (Residential Customers)
A-24-09A	Mxenergy (Canada) Ltd.
A-25-09	Nexen Marketing
A-2-10	Planet Energy (B.C.) Corp.
A-16-09	Shell Energy North America (Canada) Inc.
A-11-09	Smart Energy
A-21-09A	Summitt Energy BC LP
A-1-10A	Superior Energy Management Gas LP
A-15-09	Universal Energy Corporation

DOMESTIC ELECTRICITY SALES /2009

	Customers (#)	Revenue (\$000)	Sales (GW.h)
CROWN-OWNED ELECTRIC UTILITY			
BC Hydro and Power Authority	1,822,519	\$ 2,808,287	49,246.00
MUNICIPALLY-OWNED ELECTRIC UTILITIES			
City of Grand Forks	2,115	\$ 3,251	38.38
City of Kelowna	14,199	\$ 26,501	348.08
City of Nelson (urban)	5,689	\$ 7,227	100.6
City of Nelson (rural)	4,072	\$ 4,919	67.0
City of New Westminster	30,803	\$ 29,182	447.76
City of Penticton	16,751	\$ 27,064	340.08
District of Summerland	5,503	\$ 8,710	98.0
Total Municipally-Owned	79,132	\$ 106,854	1,439.90
INVESTOR-OWNED ELECTRIC UTILITIES			
FortisBC Inc.	110,846	\$ 188,626	2,229.00
Hemlock Electrical Services Limited	236	\$ 256	1.4
Silversmith Light & Power Corporation	11	\$ 34	0.08
Corix Multi-Utility Services Inc.			
CMUS - Sun Rivers & Sonoma Pines	771	\$ 849	11.76
Yukon Electrical Company Limited-Lower Post BC	87	\$ 133	1.0
Total Investor-Owned	111,951	\$ 189,898	2,243.24
TOTAL ALL ELECTRICAL UTILITIES	2,013,6024	\$ 3,105,039	52,929.14

ELECTRICITY NOTES

1. 1 gigawatt hour (GW.h) = 1 million kilowatt hours.
2. Figures reported are for the 2009 calendar year. Customers reported are as at December 31, 2009.
3. Revenue and sales for BC Hydro and FortisBC Inc. are net of sales to other reporting electrical utilities identified in this table.
4. There was an error in the total number of electricity customers reported for 2008/09. It was reported as 1,991,266 and should have been 1,990,910.

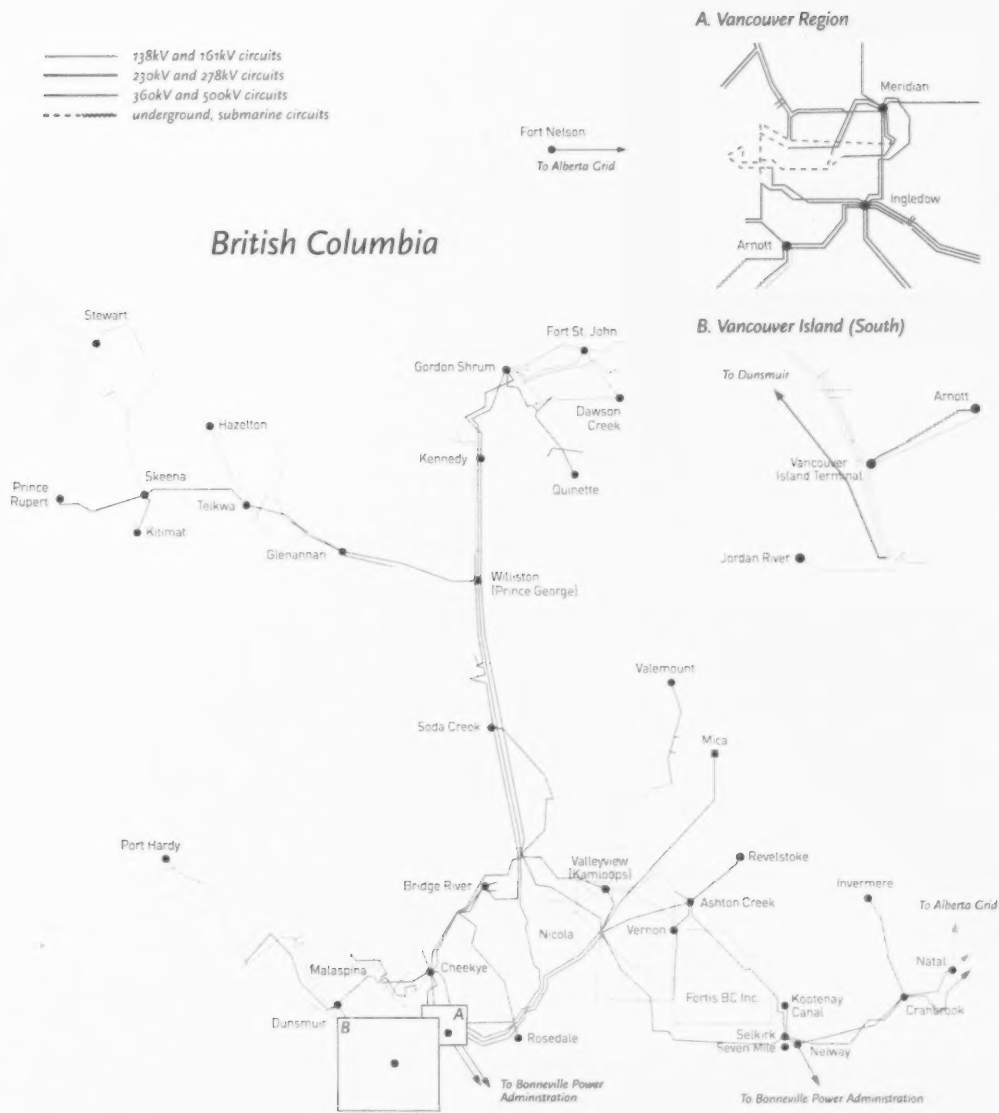
DOMESTIC GAS SALES /2009

	Customers [#]	Revenue (\$000)	Sales (GW.h)
INVESTOR-OWNED NATURAL GAS UTILITIES			
Terasen Gas Inc. ⁵			
Lower Mainland Division	583,869	\$ 1,045,859	119,931
Inland Division	229,023	\$ 321,962	45,828
Columbia Division	22,456	\$ 34,764	5,698
Fort Nelson Division	2,367	\$ 5,081	646
Revelstoke	1,573	\$ 3,335	214
Terasen Gas (Vancouver Island) Inc.			
Vancouver Island, Powell River & Sunshine Coast areas	97,708	\$ 204,559	31,178
Terasen Gas (Whistler) Inc.	2,580	\$ 14,946	649
Pacific Northern Gas (N.E.) Ltd.			
Fort St. John Inc./Dawson Creek Division	17,040	\$ 31,926	4,915
Tumbler Ridge Division	1,160	\$ 1,794	1,052
Pacific Northern Gas Ltd. (includes Granisle Grid)	20,913	\$ 49,201	6,178
Corix Multi-Utility Services Inc.			
Sun Rivers, Sonoma Pines	639	\$ 325	21
CMUS - Panorama	211	\$ 925	35
CalGas Inc. - Kickinghorse	120	\$ 295	20
CalGas Inc. - Canyon Ridge	22	\$ 15	1
Big White Gas Utility Ltd.	231	\$ 878	41
Port Alice Gas Inc.	251	\$ 376,704	14
Sun Peaks Utilities Co. Ltd.	868	\$ 2,061	84
Stargas Utilities Ltd.	247	\$ 600,709	38
TOTAL ALL GAS UTILITIES	981,278⁵	\$ 2,695,339	216,543

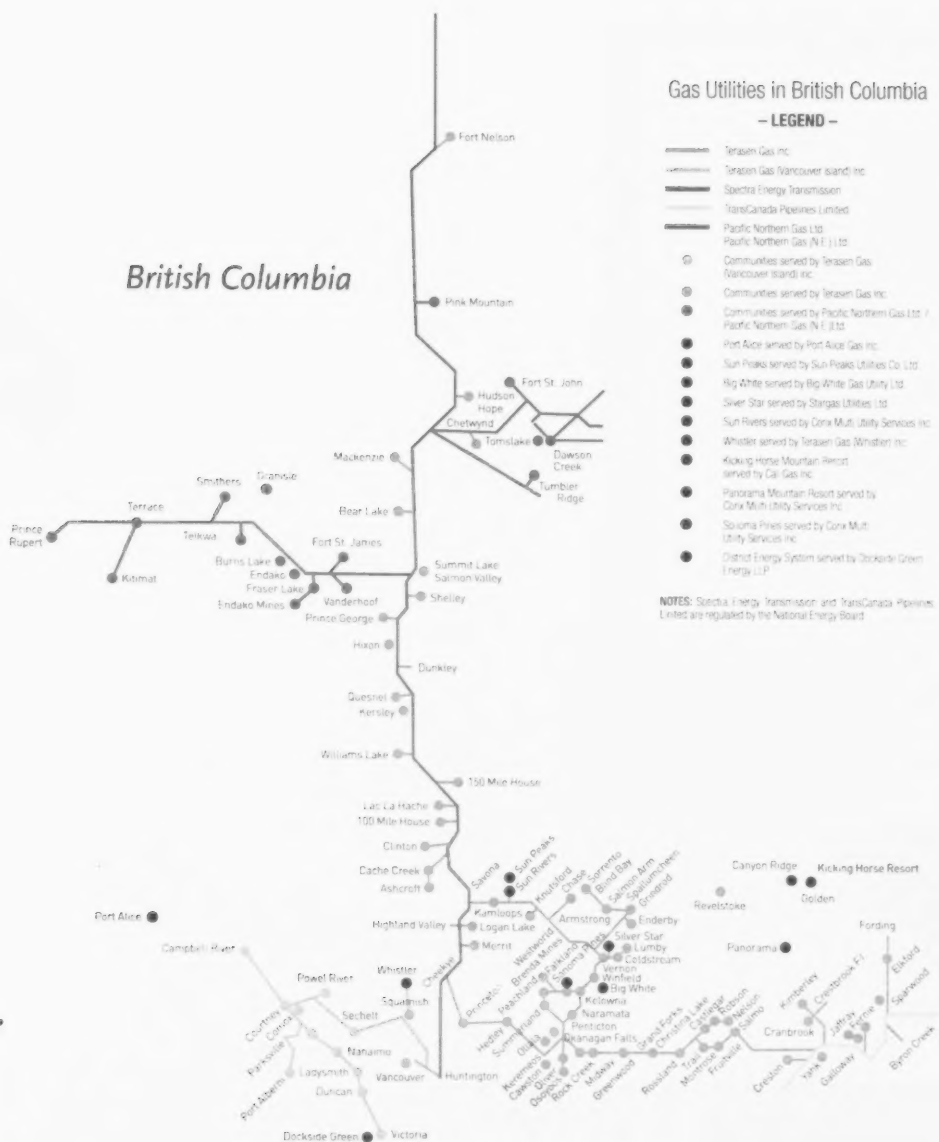
GAS NOTES

1. 1 gigajoule (GJ) is approximately equivalent to 0.910 mcf (mcf = one thousand cubic feet) or 0.0258 10³ m³ of natural gas or 0.376 mcf of propane vapour in L.P. gas grid systems.
2. Figures reported are for the 2009 calendar year. Customers reported are as at December 31, 2009.
3. Sales of GJ shown include sales to end-use customers plus gas owned by customers and transported to their industrial operations by utilities.
4. Revenues reported for natural gas utilities include only transportation margins for large industrial customers who have purchased gas supplies directly from producers or aggregators.
5. An addition error reported the 2008/09 number of customers as 1,172,387; the actual number of gas customers was 972,397.

MAIN ELECTRIC TRANSMISSION AND POWER GENERATING FACILITIES



NATURAL GAS AND GAS LIQUIDS UTILITIES



PERFORMANCE INDICATORS

Correspondence received by the Commission consists of customer complaints, utility applications, hearing documents, requests for information/assistance (not related to a proceeding), and utility reports. Not included in the following graph are customer complaints received by telephone and email or telephone requests received by the Information Services Group requesting Commission documents. These requests are processed immediately upon receipt and are not entered into the document tracking system. After a spike in the amount of correspondence received and processed by Commission staff in 2007/08, the volume returned to a level generally consistent with the previous three years.

TOTAL CORRESPONDENCE RECEIVED



HEARING AND ALTERNATIVE DISPUTE RESOLUTION DAYS

The negotiated settlement process is part of the Commission's efforts to improve the quality and efficiency of regulation. Use of the negotiated settlement process, which is also referred to as alternative dispute resolution, requires considerable work before, during, and after the negotiations. Revised "Negotiated Settlement Process: Policy, Procedures and Guidelines" were issued on January 23, 2001 [Letter L-3-01].

Alternative dispute resolution, the use of formulas for setting ROEs, and multi-year performance based settlements all contributed to the declining trend in the number of hearing days (see chart) until 2003/04. New Commission responsibilities for the regulation of ICBC's mandatory basic insurance, regulation of BCTC, and the re-regulation of BC Hydro rates contributed to the increased number of hearing days in 2004/05 and since. Matters referred to the Commission by the Lieutenant Governor in Council, such as the Kemano Completion Project and the Heritage Contract Inquiry, can have a dramatic affect on the number of hearing days; for example, in 1994 the Kemano Completion Project was reviewed over 77 hearing days and in 2003 the Heritage Inquiry was reviewed over 13 days.

DISPUTE RESOLUTION DAYS



CUSTOMER COMPLAINTS AND INQUIRIES

Inquiries and complaints are received from utility customers concerning terms and conditions of utility service, quality of service, rate increases, billing and payment requirements, disconnections, etc.

An important aspect of the Commission's mandate is to apply regulation in a manner that reflects fair, consistent and clearly identified standards. Most complaints and inquiries are resolved through discussions between the customer and the utility concerned. Unresolved issues are referred to the Commission. To facilitate communication between the Commission and the customers of regulated utilities wishing to file complaints or have points clarified, toll-free calling from anywhere in the province is available. The number of complaints and inquiries in 2009/10 decreased to 173; down from the 380 reported in 2008/09, 417 in 2007/08 and 544 in 2006/07.



SUMMARY OF 2009/2010 CUSTOMER COMPLAINTS

	Category Breakdown	Total
Big White Propane Utility		
BC Hydro and Power Authority		88
General Complaints	69	
Billing	13	
Power Surges/Outages	6	
British Columbia Transmission Corporation		
Cal-Gas Inc.		
Central Heat Distribution Limited		
Central Coast Power Corporation		
Corix Multi Utility Services Ltd.		
FortisBC Inc.		17
Hemlock Valley Electrical Services Ltd.		
Insurance Corporation of British Columbia		3
Nelson Hydro		
Pacific Northern Gas Ltd.		10
Pacific Northern Gas (N.E.) Ltd.		
Port Alice Gas Inc.		
Silversmith Power and Light		
Stargas Utilities Ltd.		
Sun Peaks Utilities Co. Ltd.		
Terasen Gas Inc.		47
General Complaints	32	
Billing	13	
Disconnected/Security Deposit Requirement	2	
Terasen Gas (Vancouver Island) Inc.	8	
Total 2009/2010 Complaints/Inquiries		173

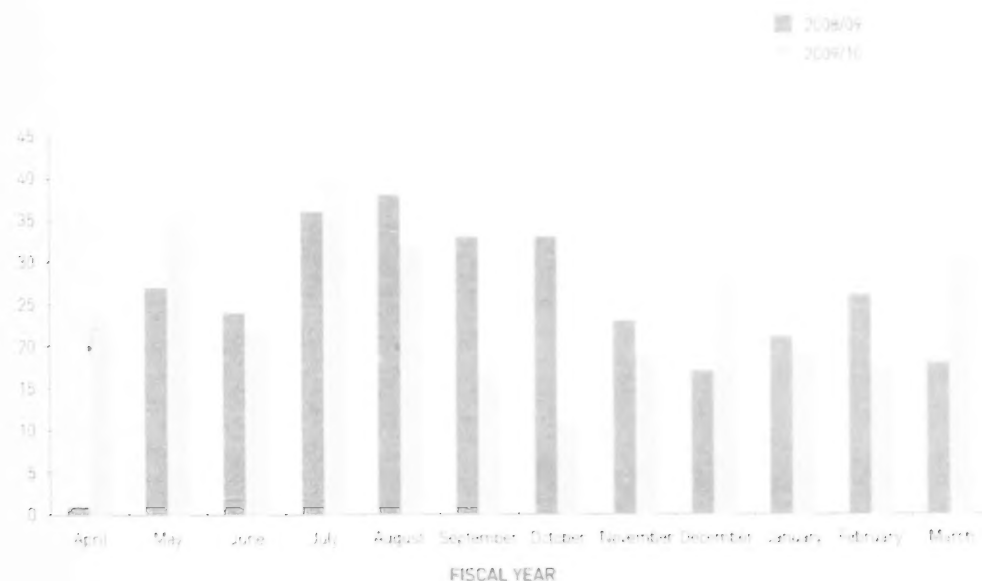
CUSTOMER COMPLAINTS REGARDING THE CUSTOMER CHOICE PROGRAM AND GAS MARKETERS

The Commission accepts complaints from the public who have a general complaint or concern about a gas marketer and who may or may not have entered into an agreement with a gas marketer under the Customer Choice Program. The types of complaints may include customer service, program administration, or gas marketer Code of Conduct issues such as salesperson conduct or marketing practices.

Many complaints are successfully resolved between the complainant and the gas marketer without the involvement of the Commission. Complainants should attempt resolution of the complaint with the gas marketer prior to contacting the Commission. However, in instances where resolution is not achieved, the Commission accepts complaints in writing, either by email, fax, or letter.

In 2009/2010, the Commission processed a total of 293 written complaints. This figure represents the number of originating written complaints received from the complainants and does not include secondary responses from the complainants, gas marketer responses, follow-up telephone enquiries, or Commission correspondence related to each complaint. There are instances when customers request to revisit a written complaint filed previously if they are not satisfied with the resolution received; customer requests to review complaints that were previously filed with the Commission are not included in the figure.

GAS MARKETER CUSTOMER COMPLAINTS



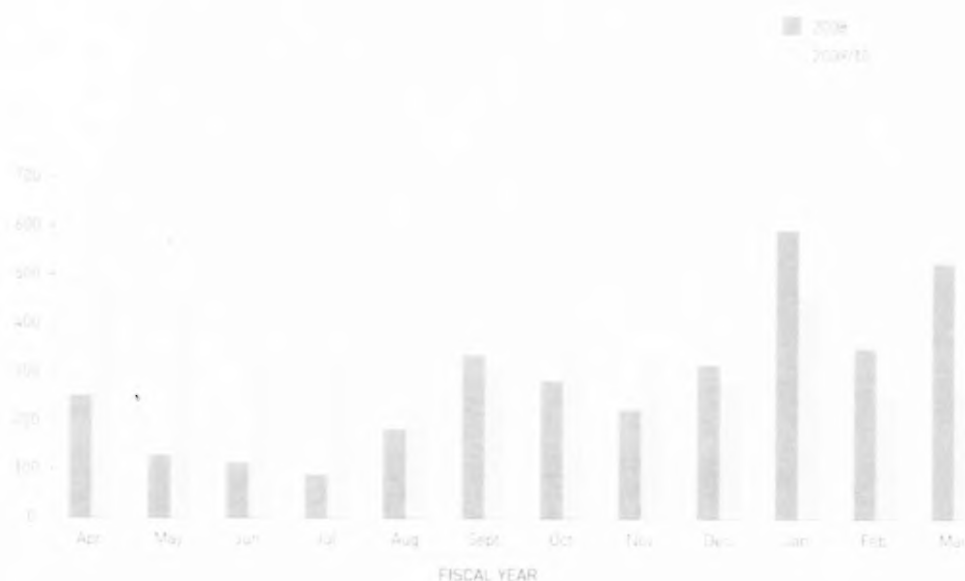
CUSTOMER DISPUTES OF GAS MARKETER CONTRACTS

Some customer complaints are brought to the Commission's attention by way of the dispute resolution system. The dispute process is available for customers who have signed a contract with a gas marketer and wish to dispute their contract. Contracts may be disputed for a number of reasons including contract term, contract price, validity of the contract, and issues on the gas marketers' compliance with the Code of Conduct.

Some disputes are successfully resolved directly between the customer and the gas marketer. Customers are advised to attempt resolution of their dispute directly with the gas marketer prior to seeking third party resolution from the Commission by lodging a dispute through the dispute resolution process.

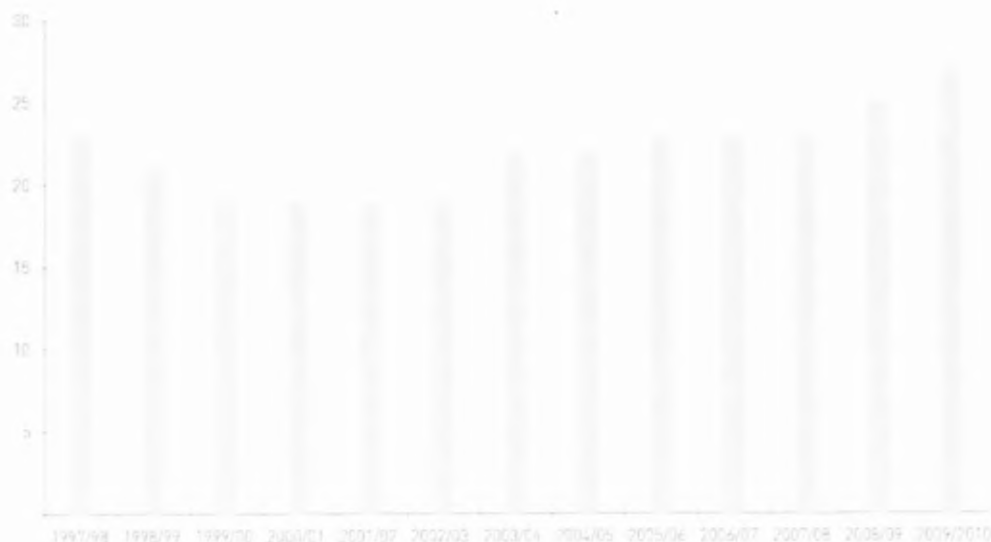
In 2009/2010, the Commission received 4,097 disputes through the dispute resolution system. This figure includes disputes adjudicated by the Commission and may include non-contested disputes in which the gas marketer agreed to cancel a customer's contract of their own accord, without a Commission determination. In adjudicated disputes, the Commission determination could either uphold the validity of a customer contract or order the cancellation or termination of a contract where non-compliance with the Code of Conduct is identified.

GAS MARKETER CUSTOMER DISPUTES



STAFFING LEVELS

Staffing levels increased from 2008/09



DIRECTIVES ISSUED

The number of Orders and Letters of Direction issued in 2009/2010 was 424; an increase from 321 in 2008/09 and 403 in 2007/08.

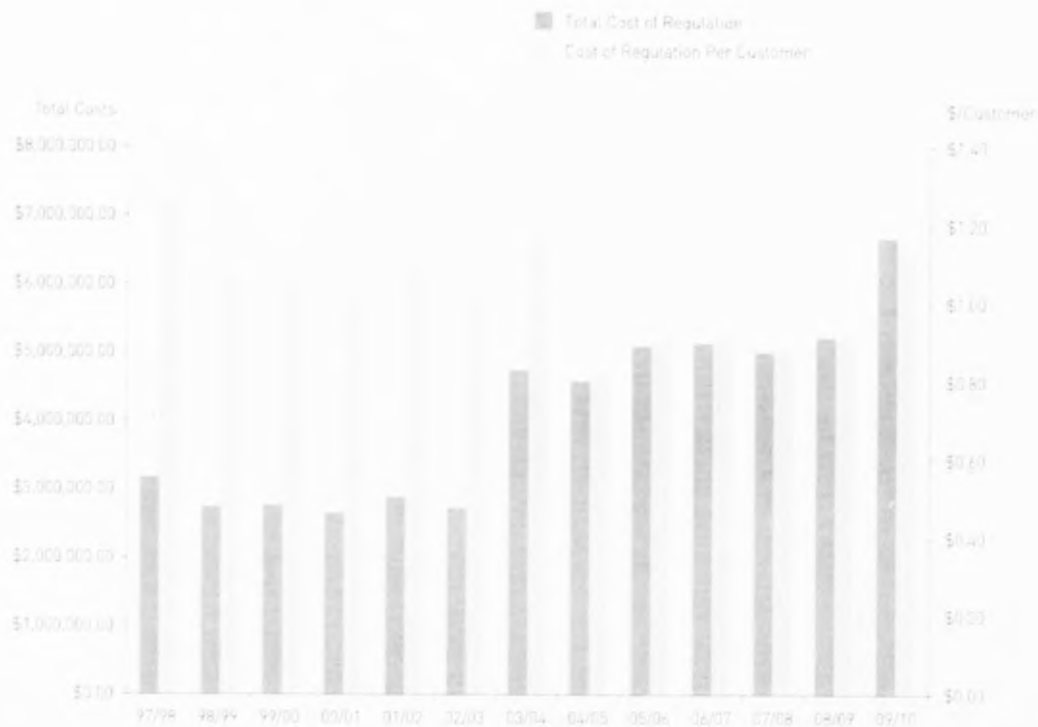


COMMISSION EXPENDITURES AND COST OF REGULATION PER CUSTOMER

The Commission's expenditures for fiscal year 2009/2010 were \$6,671,922, an increase of 27 percent from 2008/09. This was caused primarily by an increase in regulatory and human resource activities and the commencement of the Section 5 Inquiry.

The cost of regulation per customer is calculated by dividing Commission expenditures by the total number of customers of regulated utilities. For the six years prior to 2003/04, it has been under one dollar per customer, about half of what it was in the early 1990s. The rise in the cost of regulation in 2003/04 primarily reflects the return of BC Hydro to Commission regulation, the regulation of ICBC and BCTC and an increase in the number of hearing days. The increase in 2009/10 is attributed primarily to the Transmission Inquiry and review of First Nations Consultation matters.

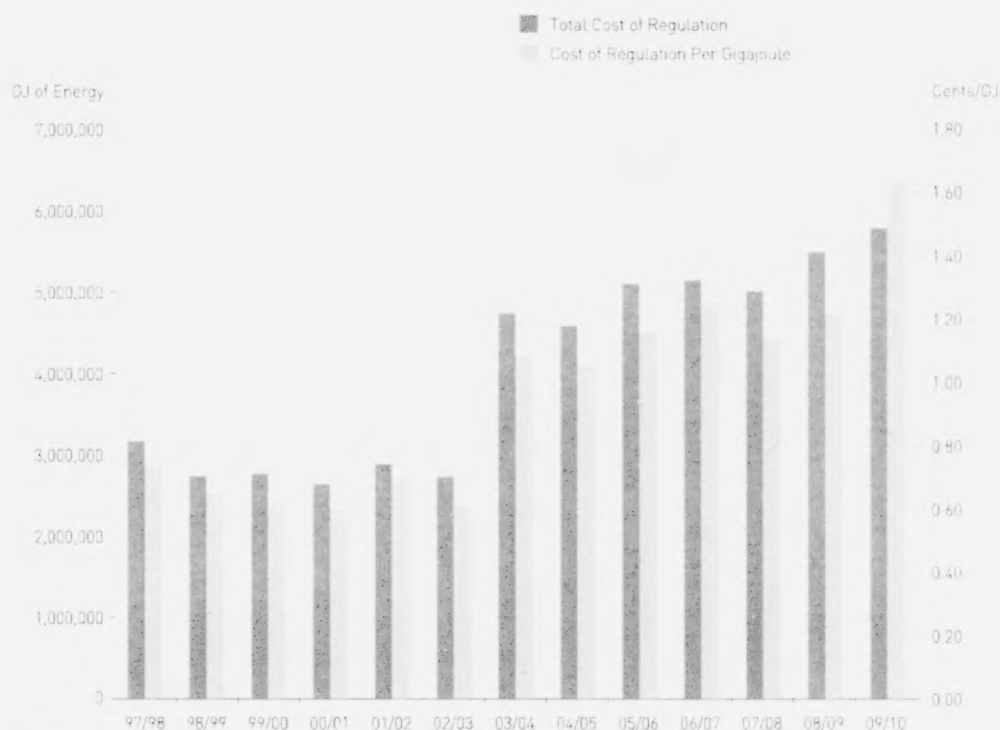
COMMISSION COSTS



COST OF ENERGY REGULATION PER EQUIVALENT GIGAJoule OF ENERGY SOLD (CENTS)

The cost of regulation per gigajoule (equivalent) of energy sold is calculated by dividing Commission energy regulation expenditures by the amount of energy sold or transported by utilities in that year.

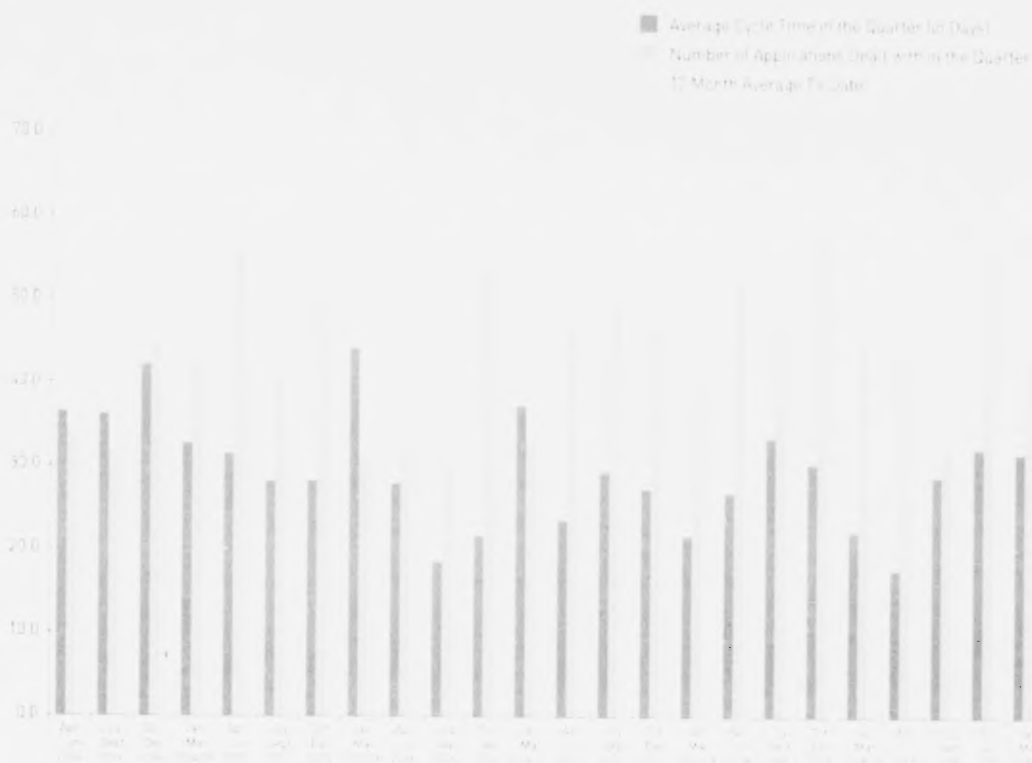
COST OF ENERGY REGULATION



CYCLE TIMES

The following graph portrays application cycles or turnaround times; the time elapsed between the receipt of an application and release of a Commission decision where a hearing is not required. These applications are managed by staff review and analysis, often with supplementary information requests and responses from the utility, but without a formal public review. Average cycle times, by quarter, ranged from 17 to 32 calendar days in 2009/2010.

CYCLE TIMES FOR NON-HEARING APPLICATIONS



More complex applications require a public review process, usually through an oral public hearing, a written public hearing, or a negotiated settlement process. Oral public hearings are quasi-judicial and adversarial, most take seven to eight months between receipt of the Application and the issuance of the Commission decision. The BCUC's written hearing process cycle times average about six months, and applications managed by a negotiated settlement process take about four months on average between receipt and disposition.

SUMMARY OF COMMISSION ORDERS ISSUED IN 2009/2010

Copies of the Commission's Orders are available from the BCUC web site at: www.bcuc.com/OrderIndex.aspx

GENERAL ORDERS

Order No.	Utility	Description
G-33-09	BCTC	Determination of Reliability Standards for Adoption in British Columbia - Regulatory Timetable/Notice of Public Comment Process
G-35-09	Terasen Whistler	Amend its Schedule of Rates effective January 1, 2009 and for a Return on Equity and Capital Structure - Reasons for Decision
G-36-09	Terasen Gas/TGVI	Energy Efficiency and Conservation Programs Application - Decision
G-37-09	Dockside Green Energy LLP	Transfer of Units in Dockside Green Energy LLP from Windmill West Properties LLP to Vancity Capital Corporation
G-38-09	BCTC	Reconsideration of the Interior to Lower Mainland Transmission Project - Regulatory Timetable
G-39-09	PNG-West	2009 Revenue Requirements for the PNG-West Service Area - Settlement Agreement
G-40-09	PNG(N.E.)	2009 Revenue Requirements for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions - Negotiated Settlement
G-41-09	BC Hydro	2007 Rate Design Application for Reconsideration of Order G-138-08
G-42-09	BC Hydro	Transmission Service Rates Customer Baseline Load F2009 Application
G-43-09	FortisBC	Net Metering Rate - Rate Schedule 95 - Regulatory Timetable/Notice of Written Hearing
G-44-09	Terasen Gas	Rate Schedule 14A for the 2009/2010 Gas Contract Year
G-45-09	Terasen Gas	Certificate of Public Convenience and Necessity for the Lions Gate Waste Water Treatment Plant Biogas Upgrading Demonstration Project - Regulatory Timetable
G-46-09	BC Hydro	Joint Industry Electricity Steering Committee Reconsideration of BC Hydro's F2009 and F2010 Revenue Requirements - Reasons for Decision
G-47-09	BCUC	British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years (Section 5) - Preliminary Inquiry Schedule
G-48-09	BC Hydro	Amend Section 2.1 of Rate Schedule 3808 Power Purchase Agreement - Decision

Order No.	Utility	Description
G-49-09	ICBC	Amendments to Schedule C of the Basic Insurance Tariff
G-50-09	PNG-West	Provision of Natural Gas Service in the Tomslake Area
G-51-09	FortisBC	Issuance of Medium Term Note Debentures
G-52-09	Terasen Whistler	Reconsideration to Vary Relevant sections in the Decision and Order G-35-09 regarding Amendments to its Schedule of Rates effective January 1, 2009 and for a Return on Equity and Capital Structure
G-53-09	Terasen Utilities	Return on Equity and Capital Structure - Regulatory Agenda/Notice of Public Hearing
G-54-09	BC Hydro	Reporting of Forced Outage January 2009 Power Surge in Mission/Stave Falls Area - Reasons for Decision
G-55-09	BC Hydro	Regulatory Account for Home Purchase Offer Program Costs
G-56-09	BCUC	Recovery of Commission Costs for the 2009/2010 Fiscal Year
G-57-09	Terasen Gas	Certificate of Public and Convenience and Necessity for the Lions Gate Waste Water Treatment Plant Biogas Upgrading Demonstration Project and for approval of an Energy Supply Contract for Biogas from the Lions Gate Waste Water Treatment Plant - One Month Suspension of Regulatory Process
G-58-09	ICBC	Order Specifying the Form and Content of, and Review Process for ICBC Universal Compulsory Automobile Insurance Revenue Requirements Applications Meeting Specified Criteria - Regulatory Timetable/Notice of Application
G-59-09	Big White	2009 Revenue Requirement
G-60-09	Terasen Whistler	Long-Term Financing
G-61-09	PNG-West	2009 Resource Plan for the PNG-West Pipeline System
G-62-09	BC Hydro	Reporting of Forced Outage November 2007 Power Surge in Goldbridge and Gun Lake Areas - Reasons for Decision
G-63-09	BC Hydro	Relief from Certain Requirements of the British Columbia Transmission Corporation Transmission Service and Interconnection Service Procedures
G-64-09	BC Hydro	Regulatory Account Regarding Actual F2009 and Forecast F2010 Smart Metering Infrastructure Program Operating Costs
G-65-09	Terasen Gas	Rate Schedule 16 - Interruptible Liquefied Natural Gas Sales and Dispensing Service

Order No.	Utility	Description
G-66-09	Sun Peaks	Amend commodity rates for Residential, Small Commercial and Large Commercial Customers effective June 1, 2009
G-67-09	BCTC	Determination of Reliability Standards for Adoption in British Columbia
G-68-09	Terasen Gas	Certificate of Public Convenience and Necessity for the Customer Care Enhancement Project Insourcing of Customer Care Services and Implementation of a New Customer Information System - Regulatory Timetable/Notice of Workshop and Procedural Conference
G-69-09	BC Hydro	2008 Long-Term Acquisition Plan - Expenditure Request for Mica Units 5 and 6 - Reasons for Decision
G-70-09	Terasen Utilities	Return on Equity and Capital Structure - Regulatory Timetable
G-71-09	FortisBC	Revised Code of Conduct and Transfer Pricing Policy and Request for Final Approval of the Brilliant Expansion Subcontractor Agreement - Regulatory Timetable
G-72-09	PNG-West	Natural Gas Commodity Charges effective July 1, 2009 for PNG-West and Granisle service areas
G-73-09	PNG (N.E.)	Natural Gas Commodity Charges effective July 1, 2009 for the Fort St. John/ Dawson Creek and Tumbler Ridge service areas
G-74-09	Terasen Gas	2009 Second Quarter Gas Cost Report and Propane Commodity Charges effective July 1, 2009 for the Revelstoke Service Area
G-75-09	BC Hydro	2008 Long-Term Acquisition Plan - Expenditure Request for the Fort Nelson Generating Station Upgrade - Reasons for Decision
G-76-09	Terasen Gas	2010 and 2011 Revenue Requirements and Delivery Rates - Notice of Procedural Conference and Regulatory Timetable
G-77-09	Terasen Whistler	Propane Commodity Charges effective July 1, 2009
G-78-09	Terasen Utilities	Return on Equity and Capital Structure - Reasons for Decision
G-79-09	Terasen Gas	Customer Care Enhancement CPCN Project Insourcing of Customer Care Services and Implementation of a New Customer Information System - Second Procedural Conference and Regulatory Timetable
G-80-09	PNG	Credit Facility Amendments and related Guarantee and Security
G-81-09	PNG (N.E.)	Credit Facility Amendments and related Guarantee and Security

Order No.	Utility	Description
G-82-09	Terasen Gas	Lions Gate Waste Water Treatment Plant Biogas Upgrading Demonstration Project - CPCN Application Withdrawn
G-83-09	BCTC	Reconsideration of the Interior to Lower Mainland Transmission Project - Regulatory Timetable/Reasons for Decision
G-84-09	TGVI	2010 and 2011 Revenue Requirements, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance as at December 31, 2008 - Notice of Workshop and Procedural Conference and Regulatory Timetable
G-85-09	Terasen Gas	Five-Year Baseload Gas Purchase Deal between Terasen Gas Inc. and BP Canada Energy Company
G-86-09	BCUC	British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years - Reasons for Decision on Scope
G-87-09	BCTC	Transmission System Capital Plan F2010 and F2011 - Reasons for Decision
G-88-09	BC Hydro	Acquisition from Teck Metals Ltd. of an Undivided One-Third Interest in the Waneta Dam and Associated Assets - Notice of Procedural Conference
G-89-09	Terasen Gas	2010 and 2011 Revenue Requirements and Delivery Rates - Notice of Second Procedural Conference and Regulatory Timetable
G-90-09	TGVI	2010 and 2011 Revenue Requirements, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance as at December 31, 2008 - Notice of Second Procedural Conference and Regulatory Timetable
G-91-09	BC Hydro	2008 Long-Term Acquisition Plan Decision
G-92-09	FortisBC	Net Metering Rate Schedule 95 - Reasons for Decision
G-93-09	Stargas	Services Agreement with Terasen Energy Service Inc.
G-94-09	BC Hydro	CPCN Application for the Gordon M. Shrum Units 1 to 5 Turbine Replacement Project - Notice of Written Hearing and Regulatory Timetable
G-95-09	BC Hydro	CPCN Application for the Mica Gas Insulated Switchgear Project - Notice of Written Hearing and Regulatory Timetable
G-96-09	BC Hydro	Relief from Certain Requirements of the British Columbia Transmission Corporation Transmission Service and Interconnection Service Procedures
G-97-09	BC Hydro	Acquisition from Teck Metals Ltd. of an Undivided One-Third Interest in the Waneta Dam and Associated Assets - Notice of Written Hearing, Workshop and Regulatory Timetable

Order No.	Utility	Description
G-98-09	BCTC	Reconsideration of the Interior to Lower Mainland Transmission Project Revised Regulatory Timetable
G-99-09	ICBC	Order Specifying the Form and Content of, and Review Process for ICBC Universal Compulsory Automobile Insurance Revenue Requirements Applications Meeting Specified Criteria - Revised Regulatory Timetable
G-100-09	BC Hydro	Transmission Service Rates Customer Baseline Load F2009 and F2010 Application
G-101-09	Terasen Gas	Gas Supply Mitigation Incentive Program for the 2009/2010 Gas Contract Year
G-102-09	BCTC	Application to Amend the BCTC Open Access Transmission Tariff and A Complaint by TransCanada Energy Ltd. Re BCTC Firm Transmission Sales to Alberta - BCTC OATT Decision
G-103-09	BCTC	Application to Amend the BCTC Open Access Transmission Tariff and A Complaint by TransCanada Energy Ltd. Re BCTC Firm Transmission Sales to Alberta - TCE Complaint Decision
G-104-09	PNG	Approval to Issue Security and for Natural Gas Supply Contract Documents
G-105-09	Terasen Gas	2009 Third Quarter Gas Costs Report and Rate Changes effective October 1, 2009 for the Lower Mainland, Inland, Columbia Service Areas
G-106-09	Terasen Gas	2009 Third Quarter Gas Costs Report and Rate Changes effective October 1, 2009 for the Fort Nelson Service Area
G-107-09	Terasen Gas	Customer Care Enhancement Project Insourcing of Customer Care Services and Implementation of a New Customer Information System - Revised Regulatory Timetable
G-108-09	BCUC	British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years - Reasons for Decision re Duty to Consult with First Nations
G-109-09	PNG	Natural Gas Commodity Charges effective October 1, 2009 for the PNG-West and Granisle Service Areas
G-110-09	PNG [N.E.]	Natural Gas Commodity Charges effective October 1, 2009 for the Fort St. John/Dawson Creek and Tumbler Ridge Service Areas
G-111-09	BCUC	British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years - Notice of Regional Sessions
G-112-09	BC Hydro	Amend Street Lighting Rate Schedules 1702 and 1703 - Regulatory Timetable

Order No.	Utility	Description
G-113-09	BCTC	Disposition of the Fiscal 2009 Deferral Accounts
G-114-09	BCUC	Inquiry into British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years - Revised Regional Session Schedule
G-115-09	FortisBC	Extend the Filing Dates for a Cost of Service Study and a Rate Design Application
G-116-09	Stargas	Alter Rates, Refinance and Acceptance of Gas Supply Contract
G-117-09	Terasen Gas	Amendment to Order G-98-05 related to an Application by Terasen Gas Inc. for Approval of Transactions Related to the Southern Crossing Pipeline and Inland Pacific Connector
G-118-09	FortisBC	2009 Annual Review, 2010 Revenue Requirements and Negotiated Settlement Process - Regulatory Timetable
G-119-09	Terasen Gas	2010 and 2011 Revenue Requirements and Delivery Rates - Notice of Negotiated Settlement Process Regulatory Timetable
G-120-09	TGVI	2010 and 2011 Revenue Requirements, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance as at December 31, 2008 - Notice of Negotiated Settlement Process Regulatory Timetable
G-121-09	Stargas	F2010 Application to Alter Rates, Refinance and Acceptance of Gas Supply Contract - Notice of Written Hearing
G-122-09	BCTC	Vancouver City Central Transmission Project Certificate of Public Convenience and Necessity - Notice of Workshop, Procedural Conference and Regulatory Timetable
G-123-09	BCUC	Reliability Standards in British Columbia Registration of Functional Entities and Monitoring and Enforcement of Reliability Standards
G-124-09	BCUC	British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years - Postponement of Regional Sessions and Fourth Procedural Conference
G-125-09	BC Hydro	Large General Service Rate Application - Notice of Workshop, Procedural Conference and Application
G-126-09	Terasen Gas	Changes to the Customer Choice Program - Notice of Written Hearing and Regulatory Timetable
G-127-09	BC Hydro	Mica Gas Insulated Switchgear Project - Revised Regulatory Timetable

Order No.	Utility	Description
G-128-09	BC Hydro	Gordon M. Shrum Units 1 to 5 Turbine Replacement Project Revised Regulatory Timetable
G-129-09	BC Hydro	Amend Street Lighting Rate Schedules 1702 and 1703
G-130-09	PNG	2010 Revenue Requirements for the PNG-West Service Area - Interim Rates and Preliminary Regulatory Timetable
G-131-09	PNG [N.E.]	2010 Revenue Requirements for the PNG-West Service Area - Interim Rates and Preliminary Regulatory Timetable
G-132-09	ICBC	Housekeeping Amendments to the Basic Insurance Tariff
G-133-09	Shaw Cablesystems	Application to continue to allow use of FortisBC Inc. Transmission Facilities - Submissions regarding Negotiated Settlement Process
G-134-09	Terasen Gas	Certificate of Public Convenience and Necessity for the Customer Care Enhancement Project/Insourcing of Customer Care Services and Implementation of a New Customer Information System - Notice of Written Hearing and Regulatory Timetable
G-135-09	Stargas	2009 Application to Alter Rates, Refinance and Acceptance of Gas Supply Contract - Regulatory Timetable
G-136-09	Terasen Whistler	2010-2011 Revenue Requirements and Rates Application - Preliminary Regulatory Timetable
G-137-09	Kyuquot Power	Amendment to Revenue Requirements along with Certain Rate Matters
G-138-09	Terasen Gas	Certificate of Public Convenience and Necessity for the Tilbury Property Purchase - Notice of Written Hearing and Regulatory Timetable
G-139-09	FortisBC	2009 Rate Design and Cost of Service Analysis - Notice of Procedural Conference and Preliminary Regulatory Timetable
G-140-09	TGVI	2010 and 2011 Revenue Requirements, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance as at December 31, 2008 - Negotiated Settlement Agreement
G-141-09	Terasen Gas	2010 and 2011 Revenue Requirements and Delivery Rates - Negotiated Settlement Agreement
G-142-09	BCTC	Aboriginal Relations Deferral Account, a Polychlorinated Biphenyls Mitigation Deferral Account, and an Amendment to the Definition of the Emergency Maintenance Deferral Account
G-143-09	Terasen Gas	Customer Choice Program Application - Amended Regulatory Timetable

Order No.	Utility	Description
G-144-09	BCTC	Reconsideration of the Interior to Lower Mainland Transmission Project Amended Regulatory Timetable
G-145-09	PNG	Issuance of Debt Securities and Granting of Security for Certain Financial Obligations
G-146-09	PNG (N.E.)	Issuance of Debt Securities and Granting of Security for Certain Financial Obligations
G-147-09	Terasen Gas	Fort Nelson Service Area Deferral Account Treatment for 2010
G-148-09	PNG	2009 Fourth Quarter Gas Cost Report
G-149-09	PNG (N.E.)	2009 Fourth Quarter Gas Cost Report
G-150-09	BC Hydro	Reconsideration of Order G-91-09 in the 2008 Long-Term Acquisition Plan - Reasons for Decision
G-151-09	ICBC	Revenue Requirements Streamlining - Amend Timetable to permit Intervener comments on paragraphs 13 and 18 of ICBC's reply submission
G-153-09	Terasen Whistler	2009 Fourth Quarter Gas Cost Rates
G-154-09	Terasen Gas	2009 Fourth Quarter Gas Cost Rates - Lower Mainland, Inland and Columbia Service Areas
G-155-09	Terasen Gas	Fort Nelson 2009 Fourth Quarter Gas Cost Rates
G-156-09	BC Hydro	Large General Service Rates - Procedural Order
G-157-09	Terasen Gas	Revelstoke 2009 Fourth Quarter Propane Cost Rates
G-158-09	Terasen Utilities	Return on Equity and Capital Structure Decision
G-159-09	BCTC	Vancouver City Central Transmission Project CPCN - Amended Regulatory Timetable
G-160-09	BCUC	Mandatory Reliability Standards - WECC Registration Information Documents
G-161-09	Terasen Gas	Rate Schedule 25 Tariff Supplement E-13
G-162-09	FortisBC	2010 Revenue Requirements Negotiated Settlement
G-163-09	BC Hydro	Southern Statistical Communities Electrification Project - Notice of Written Hearing/Timetable
G-164-09	Stargas	2009 Application to Alter Rates, Refinance and Acceptance of Gas Supply Contract - Reasons for Decision

Order No.	Utility	Description
G-165-09	Terasen Gas	Customer Care Enhancements - Amended Regulatory Timetable
G-166-09	FortisBC	2009 Rate Design and Cost of Service - Revised Regulatory Timetable and Reasons for Decision
G-167-09	BCUC	British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years - Suspension of Proceeding
G-168-09	BCTC	Generating Plant and Operational Obligations Amending Agreement
G-169-09	ICBC	Basic Insurance Tariff Amendments - Car Share Operations and Motion Picture Vehicle Use Rate Classes
G-170-09	Shaw	Continued use of FortisBC Inc. Transmission Facilities - Preliminary Procedural Conference
G-171-09	BC Hydro	Relief from Certain Requirements of the British Columbia Transmission Corporation Transmission Service and Interconnection Service Procedures
G-172-09	PNG/PNG (N.E.)	Capital Structure and Equity Risk Premium - Procedural Conference
G-173-09	BC Hydro	Acquisition from Teck Metals Ltd. An Undivided One-Third Interest in the Waneta Dam - Okanagan Nation Alliance Reply Submission
G-174-09	Birds Eye Cove Estates	CPCN, Revenue Requirements and Electric Tariff - Interim Rates
G-1-10	BC Hydro	Gordon M. Shrum Units 1 to 5 Turbine Replacement Project - Reasons for Decision
G-2-10	BCTC	Reconsideration of Interior To Lower Mainland Transmission Project - Rebuttal Evidence Admitted
G-3-10	Birds Eye Cove Power	CPCN, Revenue Requirements and Tariff - Notice of Written Hearing/Regulatory Timetable
G-4-10	Terasen Gas	Commodity Cost Reconciliation Account Allocation Methodology for Gas Costs incurred in the provision of Baseload Commodity Supply
G-5-10A	FortisBC	Revised Code of Conduct and Transfer Pricing Policy/Brilliant Expansion Subcontractor Agreement - Reasons for Decision
G-6-10	BC Hydro	Reconsideration Regarding Order G-103-09, as Confirmed by Letter L-95-09, Concerning BCTC Firm Transmission Sales to Alberta - Reasons for Decision to Proceed to Reconsideration Phase 2
G-7-10	BC Hydro	Stave Falls Spillway Gates Replacement Project - Regulatory Timetable

Order No.	Utility	Description
G-8-10	BCTC	Vancouver City Central Transmission Project - Amended Regulatory Timetable
G-9-10	BCTC	F2011 Capital Plan - Regulatory Agenda/Timetable
G-10-10	Shaw Cablesystems	Application to Continue to use FortisBC Inc.'s Transmission Facilities - Reasons and Regulatory Timetable
G-11-10	BCTC	Vancouver City Central Transmission Project - Amended Regulatory Timetable
G-12-10	BC Hydro	Acquisition from Teck Metals Ltd. An Undivided One-Third Interest in the Waneta Dam - Decision Determination/Reasons for Decision
G-13-10	PNG	Capital Structure and Equity Risk Premium - Regulatory Timetable
G-14-10	Terasen Gas	Issuance of Common Shares pursuant to Return on Equity Decision (G-158-09)
G-15-10	FortisBC	Equity Infusion - Issuance of Additional Common Shares
G-16-10	BC Hydro	Transmission Service Rates - Customer Baseline Loads F2009-F2010
G-18-10	BCTC	Columbia Valley Transmission Project - Procedural Conference
G-19-10	BCTC/FortisBC	Duck Lake Wheeling Agreement
G-20-10	ICBC	Changes to the Universal Compulsory Automobile Insurance for Fleet Plan Vehicles - Notice of Written Hearing/Timetable
G-21-10	BC Hydro	Tariff Supplement No. 74 - Customer Baseline Load Determination Guidelines
G-22-10	FortisBC	2009 Rate Design and Cost of Service - Notice of Hearing Location
G-23-10	Terasen Gas	Customer Care Enhancement Project CPCN - Decision
G-24-10	Shaw	Application to Continue to use FortisBC Inc.'s Transmission Facilities - Reasons regarding BCUC Jurisdiction to hear Shaw's Application
G-25-10	Terasen Gas	Customer Choice Program - Rate Schedule 36 - Just Energy Complaint re Backstopping Charges
G-26-10	Boralex Ocean Falls Limited Partnership	Exemption from Utilities Commission Act for Rates Charged to Residents
G-27-10	BCUC	Mandatory Reliability Standards - Mitigation Plan Filing Deadline Extension
G-28-10	Terasen Gas	Tilbury Land Purchase CPCN - Reasons for Decision

Order No.	Utility	Description
G G-29-10	BCUC	Mandatory Reliability Standards - Registration of BC Entities: British Columbia Hydro and Power Authority British Columbia Transmission Corporation FortisBC Inc. (Partial Approval only) Powerex Corp., NAES Corporation, Island Co-Generation No. 2 Inc. Arrow Lakes Power Corporation (Partial Approval only) Brilliant Power Corporation (Partial Approval only)
G-30-10	Nelson	City of Nelson Rate Increase effective April 1, 2010 Electrical Utility Amendment By-Law No. 3146, 2010
G-31-10	BC Hydro	Large General Service Rate - Reconsider and Vary Order to Allow NSP process
G-32-10	Terasen Whistler	2010-2011 Revenue Requirements - Regulatory Timetable
G-33-10	PNG-West	2010-2011 Revenue Requirements Negotiated Settlement
G-34-10	PNG [N.E.]	2010-2011 Revenue Requirements Negotiated Settlement
G-35-10	FortisBC	2009 Rate Design/Cost of Service - Zellstoff-Celgar Generator Baseline - Reasons for Decision
G-36-10	BCUC	Mandatory Reliability Standards - BCTC Assessment Report 2 - Written Comments Process
G-37-10	BCTC	F2010-F2011 Transmission System Capital Plan Reapplication for Rejected Capital Expenditures - Reasons for Decision
G-38-10	BC Hydro	Mica Gas Insulated Switchgear Project - Decision
G-39-10	Shaw Cablesystems	Application to Continue to use FortisBC Inc.'s Transmission Facilities - Reconsideration Reasons regarding Commission Jurisdiction to Review
G-40-10	Terasen Whistler	First Quarter 2010 Gas Rates
G-41-10	Terasen Gas	Revelstoke - First Quarter 2010 Gas Rates
G-42-10	Terasen Gas	Lower Mainland, Inland, Columbia - First Quarter 2010 Gas Rates
G-43-10	BCTC	F2011 Information Filing/Deferral Account to Record 2011 Capital Portfolio Project Sustaining Costs - Reasons for Decision
G-44-10	Terasen Gas	Tilbury Land Purchase CPCN Reconsideration - Procedural Timetable

Order No.	Utility	Description
G-45-10	BC Hydro	Reconsideration TransCanada Complaint [BCTC Open Access Transmission Tariff] - Reasons for Decision
G-46-10	Terasen Gas	Non-Rate Base Deferral Account for Currency Exchange Rate Differences for the Customer Care Enhancement Project
G-47-10	BC Hydro	F2011 Revenue Requirements - Procedural Conference/Regulatory Timetable
G-48-10	PNG West	Natural Gas Commodity Charges effective April 1, 2010 for the PNG West and Granisle Service Areas
G-49-10	PNG (N.E.)	Natural Gas Commodity Charges effective April 1, 2010 for the Fort St. John/ Dawson Creek and Tumbler Ridge Service Areas
G-50-10	BCUC	2010 Certificates of Public Convenience and Necessity Application Guidelines
G-51-10	BCUC	2010 First Nations Information Filing Guidelines for Crown Utilities
G-52-10	Corix	Approval of an Increase to the Gas Cost Recovery Charge - Panorama Mountain Resort
G-53-10	BCTC	F2011 Transmission Revenue Requirements and Rate Changes - Notice of Written Hearing/Regulatory Timetable
G-54-10	BCTC	Columbia Valley Transmission Project - Reasons for Decision, Regulatory Timetable and Community Input Session
G-55-10	BCUC	Mandatory Reliability Standards - Registration for Arrow Lakes Power Corporation and Brilliant Power Corporation
G-56-10	BCUC	Mandatory Reliability Standards - Registration for the City of New Westminster
G-57-10	Terasen Gas	Transportation Service Agreement between TGI and Westcoast Energy Inc. and Accounting Treatment of stage 1 Costs for a Pipeline System Expansion Study
G-58-10	BC Hydro	Southern Strategic Electrification Project Application - Reasons for Decision
G-59-10	Hydromax	Mandatory Reliability Standards - Registration of HydroMax Energy Ltd.
G-60-10	BEPC	Mandatory Reliability Standards - Registration of Brilliant Expansion Power Corporation

APPENDIX IX

CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

Order No.	Utility	Description
C-3-09	PNG (N.E.)	Tomslake Gas Distribution System
C-4-09	BC Hydro	Toad River Electrification Project - Reasons for Decision
C-5-09	FortisBC	Upgrade and Life Extension of the Corra Linn Unit 2 Generating Plant
C-6-09	BCTC	Market Operations and Development Project
C-6-09A	BCTC	Amended Market Operations and Development Project - Reasons for Decision
C-1-10	Terasen Gas	Customer Care Enhancement Project

ENERGY SUPPLY CONTRACTS

Order No.	Utility	Description
E-4-09	Terasen Gas	Deferred Exchange Agreement 2009-2011 between Terasen Gas Inc. and Avista Corporation and the Carbon Storage Agreement 2009-2011 between Terasen Gas Inc. and Alco Midstream
E-5-09	Terasen Whistler	Amending Agreement to Extend the Propane Supply Contract with MP Energy Partnership for the Period April 1, 2009 to September 30, 2009
E-6-09	PNG	Gas Supply Transaction Confirmation with EnCana Gas Marketing
E-7-09	BC Hydro	Electricity Purchase Agreement with Synex Energy Resources Ltd. from the Standing Offer Program for the Cypress Creek Project
E-8-09	BC Hydro	Electricity Purchase Agreements regarding the Bioenergy Call Phase I Request for Proposals
E-9-09	Terasen Gas	Special Provisions for the Iberdrola Renewables, Inc. Gas EDI Base Contract
E-10-09	Terasen Gas	Special Provisions for the Eagle Energy Partners I, L.P. Gas EDI Base Contract
E-11-09	BC Hydro	Fitzsimmons Creek Energy Supply Contract under Standing Offer Program
E-12-09	Terasen Gas	Seasonal Exchange Agreement with Shell Energy North America[US] L.P.
E-13-09	Stargas	Commercial Natural Gas and Management Services Agreement with Access Gas Services
G E-14-09	BC Hydro	Electricity Purchase Agreement with Dokie General Partnerships

Order No.	Utility	Description
G E-15-09	Stargas	Gas Purchase Transaction Confirmation with Access Gas Services
E-16-09	BC Hydro	Electricity Purchase Agreement with Tembec Industries Inc.
E-17-09	BC Hydro	Electricity Purchase Agreement with Tolko Industries Ltd.
E-18-09	PNG	2009/2010 Gas Supply Contracts (November 2009 to October 2010)
E-19-09	BC Hydro	Standing Offer Program - Energy Supply Contract with Cedar Road LFG Inc.
E-20-09	Terasen Gas	FET Resources Ltd. - Special Provisions for Gas EDI Base Contract
E-1-10	Terasen Gas	Transport Agreement with Westcoast Energy Inc.
E-2-10	Terasen Gas	Gas Electronic Data Interchange Agreement with Tenaska Marketing Ventures
E-3-10	FortisBC	Electricity Purchase Agreement with Teck Metals Ltd. dated September 22, 2009
E-4-10	FortisBC	Electricity Purchase Agreement with Teck Metals Ltd. dated October 30, 2009
E-5-10	Terasen Gas	Natural Gas Supply Contracts for the 2009/2010 Contract Year
E-6-10	BC Hydro	Standing Offer Program Electricity Purchase Agreement w/Canoe Creek Hydro Company Ltd.
E-7-10	Terasen Gas	Northwest Pipeline Corporation - Jackson Prairie Storage JPS Contracts and NPC Transportation Contracts
E-8-10	Terasen Gas	Aiken Creek Gas Storage ULC - Storage Agreement
E-9-10	Terasen Gas	Deferred Exchange Agreement (DEA) Amendment - Huntingdon Gas Supply between Terasen and Avista Corporation
E-10-10	BC Hydro	Energy Supply Contract - Bone Creek

PARTICIPANTS ASSISTANCE/COST AWARDS

Order No.	Utility	Description
F-9-09	Terasen	Upgrade of the Transmission Pipeline Crossing of the South Arm of the Fraser River - \$8,070.65
F-10-09	FortisBC	Benvoulin Substation Project CPCN - \$3,781.15
F-11-09	Terasen Gas	Gas Supply Mitigation Incentive Program for the 2008/09 Gas Contract Year - \$3,075.45
F-12-09	Energy Solutions for Vancouver Island	Reconsideration of Commission Order F-25-08 - \$2,100
F-13-09	BC Hydro	Fiscal 2009 and Fiscal 2010 Revenue Requirements - \$574,023.55
F-14-09	FortisBC	Reconsideration of the FortisBC CPCN for the Ellison Substation Project Decision and Orders C-4-07 and G-75-07 - \$8,870.40
F-15-09	Terasen Whistler	2009 Revenue Requirements and Return on Equity and Capital Structure - \$8,246.00
F-16-09	TGVI	2008 Settlement Update/2009 Revenue Requirements - \$56,413.67
F-17-09	BC Hydro	Amend Section 2.1 of Rate Schedule 3808 Power Purchase Agreement - \$30,515.26
F-18-09	Terasen Gas	Customer Choice Program Enhancements and Additional Customer Education Funding Application - \$2,956.80
F-19-09	PNG-West/PNG(N.E.)	2009 Revenue Requirements - \$10,087.88
F-20-09	BCUC	British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years - \$110,486.12
F-21-09	BCTC	Reconsideration of the Interior to Lower Mainland Transmission Project - Reasons for Decision on Interim Awards - \$113,012.38
F-22-09	BC Hydro	2008 Long-Term Acquisition Plan - \$666,596.75
F-23-09	FortisBC	Net Metering Tariff - \$4,358.55
F-24-09	BCTC	Transmission System Capital Plan F2010 and F2011 - \$38,084.73
F-25-09	BC Hydro	Toad River Electrification Project - \$4,328.62
F-26-09	BCUC	British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years - \$11,944.02

Order No.	Utility	Description
G G F-27-09	BCTC	Interior to Lower Mainland Transmission Project Reconsideration - Interim Funding Awards - Reasons for Decision - \$25,287.34
F-28-09	FortisBC	Revised Code of Conduct and transfer Pricing Policy - \$3,015.25
F-29-09	BCTC	Open Access Transportation Tariff/TransCanada Energy Complaint - TransAlta Corporation Reasons for Decision - Denied
F-30-09	BC Hydro	Acquisition from Teck Metals Ltd. of an Undivided One-Third Interest in the Waneta Dam and Associated Assets - Interim Award - \$27,512.50
F-31-09	IPPBC	Reconsideration of F-22-09 - BC Hydro 2008 LTAP - \$30,375
F-32-09	BCUC	Section 5 Inquiry - Interim PACA Awards for Interim Funding Period 2 - \$311,217.79
F-33-09	BC Hydro	Acquisition from Teck Metals Ltd. of an Undivided One-Third Interest in the Waneta Dam and Associated Assets - Interim PACA funding to the Simixt Nation - \$22,750.00
F-34-09	BCUC	British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years - Interim PACA Awards for Interim Funding Period 3 - \$5,462.40
F-1-10	BCTC	Interior to Lower Mainland Transmission Project Reconsideration - Second Interim Awards - \$283,605.78
F-2-10	TGVI	2010-2011 Revenue Requirements/Cost of Service/Rate Design - \$15,394.12
F-3-10	Terasen Gas	2010-2011 Revenue Requirements - \$22,543.15
F-4-10	TGVI	2010-2011 Revenue Requirements/Cost of Service/Rate Design - \$20,354.04
F-5-10	FortisBC	2010 Revenue Requirements - \$21,526.25
F-6-10	Terasen Gas	Customer Choice 2009 Program Summary and Recommendations - \$2,365.02
F-7-10	Terasen Utilities	Return on Equity and Capital Structure - \$238,337.86
F-8-10	BCUC	British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years - Period 4 Interim PACA Awards - \$179,037.39
F-9-10	FortisBC	2010 Revenue Requirements - \$682.70
F-10-10	PNG-West	2010 Revenue Requirements - \$12,025.13
F-11-10	PNG (N.E.)	2010 Revenue Requirements - \$9,431.63

APPENDIX IX

PETROLEUM

Order No.	Utility	Description
P-3-09	Plateau	Western System Toll Increases - Interim Rates
P-4-09	Plateau	Western System Toll Increases Decision
P-5-09	TMJF	2010 Tariff Revisions
P-6-09	Plateau	Northeast BC Pipeline and Blueberry Pipeline Revised tariff and Supplemental Toll Information

COMMISSION LETTERS

Order No.	Utility	Description
L-24-09	BCTC	Open Access Transmission Tariff and A Complaint by TransCanada Energy Ltd. re: Service Agreement between TCE and BCTC for Long Term Firm Point-to-Point Transmission Service - Submissions regarding the Alberta Electric System Operator
L-25-09	BCTC	Transmission System Capital Plan F2010 to F2011 - Amended Regulatory Timetable
L-26-09	BCTC	Open Access Transmission Tariff and A Complaint by TransCanada Energy Ltd. regarding Service Agreement between TCE and BCTC for Long-Term Firm Point-to-Point Transmission Service - Second Procedural Conference and Procedural Issues
L-27-09	Terasen Gas	Gas Supply Mitigation Incentive Program 2007/08 - BCUC Staff Overview Report
L-28-09	BC Hydro	Reporting on Forced Outage Downtown Vancouver Outage - July 2008
L-29-09	Terasen Whistler	Phase 2 Reconsideration of Order G 35-09 and Decision dated April 7, 2009 - 2009 Revenue Requirements Application and for a Return on Equity and Capital Structure
L-30-09	Terasen Gas	Customer Choice Program - Terasen Gas Website: Price Depository
L-31-09	PNG-West	Price Risk Management Plan - Implement Fixed Price Swaps
L-32-09	BCTC	2009 Network Economy Meeting Cancellation
L-33-09	Terasen Gas	2009 Price Risk Management Plan (November 2009 - October 2012)
L-34-09	Terasen Gas	Revelstoke Service Area Propane Price Risk Management Plan 2009 - 2010

Order No.	Utility	Description
G L-35-09	BCTC	Interior to Lower Mainland Transmission Project - Revised Regulatory Timetable
L-36-09	TGVI	2009 Price Risk Management Plan (November 2009 - October 2014)
L-37-09	BCTC	Order in Council 074, 2009 - F2010 Cost Reductions
L-38-09	Terasen Gas	Certificate of Public Convenience and Necessity for the Customer Care Enhancement Project Insourcing of Customer Care Services and Implementation of a New Customer Information System - Direction to discuss issues at the Workshop and Procedural Conference
L-39-09	ICBC	Update on Other Operator and Year 2 Rate Design Adjustments
L-40-09	Terasen Gas	Fort Nelson Service Area 2009 Second Quarter Gas Cost Report/Gas Cost Reconciliation Account
L-41-09	TGVI	Second Quarter 2009 Gas Cost Report
L-42-09	PNG-West	2009 Annual Contracting Plan and Price Risk Management Plan dated April 30, 2009
L-43-09	Terasen Gas	2009 Second Quarter Gas Cost Report - Commodity Cost Reconciliation Account and Midstream Cost Reconciliation Account for the Lower Mainland, Inland and Columbia Service Areas
L-44-09	Terasen Gas	Company Use Gas Hedging for 2010 - 2011
L-45-09	TGVI	2009 Price Risk Management Plan (November 2009 - October 2014)
L-46-09	ICBC	2009 Revenue Requirements
L-47-09	FortisBC	Credit Facility Renewal
L-48-09	BC Hydro	Electricity Purchase Agreement with Rio Tinto Alcan Inc. as an Energy Supply Contract Pursuant to Section 71 - Rio Tinto Alcan Inc. Request for Deferral of the Re-opening of the Proceeding
L-49-09	Terasen Gas	Revelstoke 2009-10- Price Risk Management Plan
L-50-09	Terasen Gas	2010 and 2011 Revenue Requirements and Delivery Rates Application - Procedural Conference Issues
L-51-09	FortisBC	Revised Code of Conduct and Transfer Pricing- Intervener Submission Extension
L-52-09	Stargas	Confidential Acceptance of Price Mitigation Strategy 09/10 and 10/11

APPENDIX IX

Order No.	Utility	Description
G L-53-09	BC Hydro	Remote Community Electrification Project - Toad River Application - Workshop
L-54-09	BC Hydro	Complaint by City of Vancouver - Re: Pathway and Bikeway Reclassification Tariffs
L-55-09	ICBC	Basic Insurance Year 2 Rate Design Adjustments to Base Rates
L-56-09	BC Hydro	Line Contractors' Association of BC Complaint
L-57-09	BCTC	Interior to Lower Mainland Transmission Line Reconsideration - Amended Regulatory Timetable
L-58-09	Terasen Gas	2009/2010 Annual Contracting Plan (November 2009 - October 2010)
L-59-09	TGVI	2009/2010 Annual Contracting Plan (November 2009 - October 2010)
L-60-09	AltaGas	Gas Marketer Licence Renewal - Information Request
L-61-09	BC Hydro	Acquisition from Teck Metals Ltd. An Undivided One-Third Interest in the Waneta Dam - Amended Regulatory Timetable
L-62-09	Nexen	Gas Marketer Licence Renewal - Information Request
L-63-09	Just Energy	Gas Marketer Licence Renewal - Information Request
L-64-09	Active	Gas Marketer Licence Renewal - Information Request
L-65-09	Direct	Gas Marketer Licence Renewal - Information Request
L-66-09	Ag/Firefly	Gas Marketer Licence Renewal - Information Request
L-67-09	Superior	Gas Marketer Licence Renewal - Information Request
L-68-09	BC Hydro	Transmission Service Rates Customer Baseline Load F2009 F2010
L-69-09	Summitt	Gas Marketer Licence Renewal - Information Request
L-70-09	Smart	Gas Marketer Licence Renewal - Information Request
L-71-09	PNG	Modification to Gas Price Hedging Schedule [L-42-09]
L-72-09	TGVI	2009 Third Quarter Report on Gas Costs/Annual Revenue Surplus/Deficiency
L-73-09	Terasen Gas	Revelstoke - 2009 Third Quarter Report on Propane Costs
L-74-09	Terasen Whistler	2009 Third Quarter Gas Costs
L-75-09	Terasen Gas	Receipt Point Fuel Gas Percentages Unchanged
L-76-09	Just Energy	Gas Marketer Licence Renewal - Information Request

Order No.	Utility	Description
G L-77-09	Terasen Gas	Customer Care Enhancements - Notice of PACA Budget Deadline
L-78-09	Nexen	Gas Marketer Licence Renewal - Information Request No. 2
L-79-09	Active	Gas Marketer Licence Renewal - Information Request Compliance
L-80-09	BCTC	Section 5 - Requests for an Extension to Filing Deadline
L-81-09	DEML	Gas Marketer Licence Renewal - Information Request Compliance
L-82-09	Superior	Gas Marketer Licence Renewal - Information Request Complaint statistics
L-83-09	Terasen Gas	Customer Care Enhancements Project - Release of Confidential Material to Interveners
L-84-09	BCUC	British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years - Second Request for Extension to Evidence Filing Deadlines (BC Hydro-BCTC) Exhibit A-25
L-85-09	Summitt Energy	Gas Marketer Licence Renewal Information Request regarding Complaint Numbers quoted in renewal application
L-86-09	Active	Letter dated September 30, 2009 confirming that to date Active had not yet filed its responses to L-79-09
L-87-09	Terasen Gas	Customer Care Enhancements - Exhibit A-9 - Request for Comments regarding Hansen Technologies' written submission on confidential filings
L-88-09	Terasen Gas	2009 Price Risk Management Plan (November 2009 - October 2012) Trigger Prices - Amendment
L-89-09	BCUC	British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years - Exhibit A-27 Third Extension for filing of Evidence by BC Hydro and BCTC
L-90-09	BC Hydro	Transmission Service Rate F2008 Annual Report - Regulatory Timetable
L-91-09	BCUC	British Columbia's Electricity Transmission Infrastructure and Capacity Needs for the Next 30 Years - Exhibit A-32 Postponement of Regional Sessions
L-92-09	BC Hydro	Reconsideration/Variance of 2008 LTAP Order G-91-09 - Timetable
L-93-09	Terasen Utilities	Return on Equity and Capital Structure - Approval to refer to National Energy Board Decision in Argument
L-94-09	MxEnergy	Letter outlining Deficiencies in Gas Marketer Application and supporting Assets/Liability Ratio

APPENDIX IX

L-95-09	BCTC	Clarification of Commission Decision regarding TransCanada Energy Complaint re Open Access Transmission Tariff - Firm Sales to Alberta
L-96-09	Terasen Gas	Customer Care Enhancement Project - Exhibit A-10 Confirmation of Terasen's review of Confidential Information Request Responses
L-97-09	BCTC	Interior to Lower Mainland Transmission Project Reconsideration - Amended Timetable
L-98-09	BC Hydro	Acquisition from Teck Metals Ltd. An Undivided One-Third Interest in the Waneta Dam - Revised Regulatory Timetable to extend the date for filing Intervener Evidence
L-99-09	FortisBC	BC Hydro Rate Schedule 3808 Section 2.1 Amendment - Response to FortisBC re: Establishment of OASIS system not required at this time
L-100-09	BC Hydro	Acquisition from Teck Metals Ltd. An Undivided One-Third Interest in the Waneta Dam -- Sinixt Extension to filing Intervener Evidence
L-101-09	BC Hydro	2008 Long Term Acquisition Plan - Request to Amend Directive 31
L-102-09	BCUC	Utility Return on Equity Calculations
L-103-09	BC Hydro	Acquisition from Teck Metals Ltd. An Undivided One-Third Interest in the Waneta Dam -- Written Hearing Process Timetable
L-104-09	Active Energy	Customer Enrolment Inquiry
L-105-09	BC Hydro	Acquisition from Teck Metals Ltd. An Undivided One-Third Interest in the Waneta Dam - - Clarification of Regulatory Timetable in Exhibit A-11 - Letter L-100-09
L-106-09	BC Hydro	Electricity Purchase Agreements - Request for Generator Baseline Guidelines - Information Request
L-107-09	BCTC	Open Access Transmission Tariff Amendment/TransCanada Energy Inc. Complaint - Request Comments on BC Hydro Reconsideration Request
L-108-09	PNG	2010 Revenue Requirements - Negotiated Settlement Process Regulatory Timetable
L-109-09	PNG (N.E.)	2010 Revenue Requirements - Negotiated Settlement Process Regulatory Timetable
L-110-09	BCTC	Vancouver City Central Transmission CPCN - Request for Intervener Comments on BCTC's two Procedural Order Submissions
L-111-09	PNG-West	2010 Revenue Requirements - Amend Regulatory Timetable

Order No.	Utility	Description
G L-112-09	Shell Energy	Request for Exemption or Relief from Certain Licence Requirements regarding Audited Financial Statements - Denied
L-113-09	Terasen Whistler	2010-2011 Revenue Requirements- Request Comments regarding further process
L-1-10	PNG/PNG (N.E.)	Capital Structure and Equity Risk Premium - Procedural Conference Time Change
L-2-10	Terasen Gas	Tilbury Land Purchase CPCN - Regulatory Timetable Revised
L-3-10	Planet Energy	Gas Marketer Licence Application - Request for Additional Information
L-4-10	Terasen Whistler	2010 Revenue Requirements - Amended Regulatory Timetable
L-5-10	Superior	Gas Marketer Audited Financial Statements -Information Request
L-6-10	Terasen Gas	Customer Care Enhancements - Oral Phase of Argument
L-7-10	BCTC	Interior to Lower Mainland Transmission Project Reconsideration - Reasons for Decision re: Kwikwetlem Production of Confidential Information
L-8-10	Terasen Whistler	2010 Revenue Requirements - Amended Regulatory Timetable
L-9-10	BCTC	F2011 Financial Information/Deferral Account for 2011 Capital Portfolio Project Sustaining Costs
L-10-10	Hemlock Valley	Regulatory Compliance Requirements - Information Request
L-11-10	Terasen Gas	Scope of Work for Comprehensive Study regarding the 2009/2010 Annual Contracting Plan
L-12-10	Terasen Gas	Gas Supply Mitigation Incentive Program for 2008/2009 - Commission Staff Report
L-13-10	BC Hydro	Large General Service Rate Application - Reconsider G-156-09/Proceed to Phase 2 of Reconsideration process
L-14-10	Silversmith	Complaint - BC Hydro Line Repair Charge and Sale of Power to BC Hydro
L-15-10	BCTC	Timing of Fiscal 2011 BC Hydro Owner's Revenue Requirement; BCTC Allowed Return on Deemed Equity and BCTC Point to Point Transmission Service Revenue Forecast
L-16-10	BCTC	Interior to Lower Mainland Transmission Project Reconsideration - Exhibit A-31, Final Argument Extension Request
L-17-10	Shaw Cablesystems	Application to Continue to use FortisBC Inc.'s Transmission Facilities - Extension to Submission Deadline

APPENDIX IX

Order No.	Utility	Description
L-18-10	PNG/PNG (N.E.)	Capital Structure and Equity Risk Premium - Extension to Information Request Responses Filing Deadline
L-19-10	Birds Eye Cove	CPCN Application, Revenue Requirements and Tariffs - Exhibit A-5 Amended Regulatory Timetable to allow BECP to respond to Information Requests
L-20-10	BC Hydro	Revised Rate Schedule 1823 - Transmission Service Rates Customer Baseline Load F2009 and F2010
L-21-10	Terasen Gas	Fort Nelson Service Area - First Quarter Gas Rates
L-22-10	TGVI	First Quarter Gas Costs Report and Rate Stabilization Deferral Account
L-23-10	BCTC	Interior to Lower Mainland Transmission Project Reconsideration - Extension to Intervener Argument Deadline
L-24-10	BC Hydro	Energy Supply Contract Filing - Information Request Bone Creek Report on Interconnection Costs
L-25-10	BCUC	Mandatory Reliability Standards - Western Electricity Coordinating Council Form Changes - Mitigation Plan Submittal Form
L-26-10	BCTC/FortisBC	Mandatory Reliability Standards - Assignment Agreements Request for Comments
L-27-10	Active Energy	Customer Dispute - Contract Cancellation and Refund - Request to provide Dispute Documentation

STANDARD ABBREVIATIONS & ACRONYMS

Allowance for Funds Used During Construction	AFUDC
Alternative Dispute Resolution	ADR
Apartment Customer Rates	ACR
Big White Utility Ltd.	Big White
British Columbia Hydro and Power Authority	BC Hydro
British Columbia Transmission Corporation	BCTC
Cal-Gas Inc.	CalGas
Central Heat Distribution Limited	Central Heat
Certificate of Public Convenience and Necessity	CPCN
Conx Multi-Utility Services Inc.	Conx
Energy for our Future: A Plan for BC	Energy Plan or Energy Policy
FortisBC Inc.	FortisBC
Gas Cost Reconciliation Account	GCRA
Gas Cost Variance Account	GCVA
Hemlock Valley Electrical Services Limited	Hemlock Valley
Independent Power Producers	IPPs
Insurance Corporation of British Columbia	ICBC
Insurance Corporation of British Columbia	ICBC
Kinder Morgan, Inc.	Kinder Morgan
Kyuquot Power Ltd.	Kyuquot Power
Large General Service	LGS
Natural Gas Marketers	NGM
Natural Gas Vehicles	NGV
Negotiated Settlement Process	NSP
Pacific Northern Gas (N.E.) Ltd.	PNG (N.E.)
Pacific Northern Gas Ltd.	PNG PNG-West
Plateau Pipe Line Ltd.	Plateau
Port Alice Gas Inc.	Port Alice Gas
Return on Common Equity	ROE
Silversmith Light & Power Corporation	Silversmith
Small General Service	SGS
Stargas Utilities Ltd.	Stargas
Sun Peaks Utilities Co., Ltd.	Sun Peaks
Sun Rivers Services Corp.	Sun Rivers
Terasen Gas (Vancouver Island) Inc.	Terasen VI, TGV
Terasen Gas (Whistler) Inc.	Terasen Whistler, TGV
Terasen Gas Inc. (subsidiary of Terasen Inc.)	Terasen, Terasen Gas, TGI
The Corporation of the City of Nelson	City of Nelson
The Yukon Electrical Company Limited	Yukon Electrical
Trans Mountain (Jet Fuel) Inc.	Trans Mountain
Utilities Commission Act	the Act, UCA

GLOSSARY OF TERMS

allowance for funds used during construction (AFUDC) The amount a regulated entity is allowed to earn to recover its cost of financing assets under construction. AFUDC is equal to the average cost of the construction work in process, times a financing rate which is usually equal to the entity's cost of capital rate. AFUDC is not recovered immediately through rates; it is included in the cost of the related assets and recovered in future periods through the depreciation charge.

allowed rate of return The rate of return a regulated entity is allowed the opportunity to earn. When applied to the rate base, the allowed rate of return provides an amount equal to the cost of financing the investment required for regulated operations. The financing costs include both the cost of debt and the cost of equity.

alternative dispute resolution (ADR) See negotiated settlement process.

application for reconsideration An application to have the Commission reconsider, vary, or rescind a decision or order previously issued.

burnertip rate The rate charged for gas at the customer's meter, including the delivery charge, fixed monthly charge and gas commodity charge. It is usually calculated as an annual average rate based on typical annual consumption for the customer class.

capital cost The fixed costs associated with the construction of an energy facility, including land and siting costs, material and labour costs, allowance for funds used during construction, and other applicable overhead charges.

cogeneration The generation of electric power in conjunction with the use of steam in an industrial or space heating process, using waste heat from one process to drive the other. Cogeneration is more efficient compared to traditional thermal generating plants.

commercial commodity unbundling (also see residential commodity unbundling) The program provides commercial customers (Rates 2, 3 and 23) of Terasen Gas Inc. with the opportunity to enter into a natural gas commodity supply arrangement with a licensed gas marketer.

common carrier(s) An energy transportation provider, typically a crude oil or natural gas pipeline which provides service on a non-discriminatory basis to all potential shippers.

cost of service The total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes and cost of capital. The cost of service is also known as revenue requirements.

cost of service study A study to determine the cost of service by class of service and/or customer. These studies are used to help determine how the revenue requirements are to be allocated among the rates for the various services/customers.

cross subsidization Increasing the rates for one service or class of customers so the rates of another service or class of customers can be reduced below cost.

debt-equity ratio The ratio of money borrowed by the utility to money invested in the utility by shareholders. There is a theoretical optimum for this for each utility.

deferral account An account that records the deferral of a cost or revenue until a future date. A deferred asset account records a cost that would normally be expensed and recovered in the current period, but which is to be expensed or recovered in a future period. A deferred liability account records an amount recovered in the current period, to cover costs of providing service in a future period.

demand-side management (DSM) Efforts to modify customer demand patterns by either increasing end-use energy efficiency or reducing fluctuations in energy demand.

distributed generation Generation that is relatively small scale and located close to the final customer.

distribution system The portion of an electric or natural gas transportation infrastructure that connects end-users to bulk production or transportation facilities.

energy losses Energy lost during transportation from suppliers to end-users. Energy losses on a typical natural gas system are around 1 to 3 percent. Energy losses on a large electric system are around 5 to 8 percent.

export sales Bulk sales of electricity or natural gas outside of British Columbia.

firm capacity The amount of instantaneous energy production or transportation capacity that is available at a defined time.

firm energy The amount of energy that is available over a defined period of time.

GLOSSARY OF TERMS

fixed cost Costs associated with an energy production or transportation facility which must be paid whether the plant operates or not. Fixed costs generally include capital costs, contract demand charges and operating costs which are committed or unaffected by production levels.

gas cost reconciliation account (GCRA) / gas cost variance account (GCVA) A deferral account which accumulates the variance in actual gas costs from the actual gas revenue recovered in customer rates.

green power rates Rates charged for electricity service from generators which do not pollute or damage the environment. Different groups define "green" power with various levels of restriction. For example, a run of the river hydro plant may be included while a new dam and reservoir may be excluded.

hydroelectric energy, hydroelectricity Electric energy produced by water falling through a turbine generator. In British Columbia, hydroelectricity is the dominant form of electric energy production.

incentive regulation Regulation which rewards utilities for cost savings or other actions which are desired by ratepayers.

independent power producers (IPPs) Non-utility electric energy generators. Until the early 1970s, independent power producers were rare. With recent changes in utility technology and economics, they have become more common. Many issues relating to restructuring of the utility industry involve the role of independent power producers in a deregulated energy market.

information requests Questions posed to those who have filed evidence for a hearing, pertaining to the evidence they have filed. Information requests and their responses are made prior to the hearing, in writing, and become evidence in the hearing. Information requests are also referred to as "interrogatories".

interim rate A rate which is put in place until the regulator can determine the final rates. If the final rates are lower than the interim rates, customers are generally refunded their over-contributions with interest for the period of time the interim rates existed.

interruptible energy, interruptible service Energy flow which can be reduced or cut off on relatively short notice when needed by other customers. Generally, interruptible energy is sold by contract at a reduced price or without fixed charges to end-users, with specific terms and conditions governing interruptibility rights.

investor-owned utility A utility owned by private shareholders.

joule A measure of energy or work done equal to a force of 1 newton applied through a distance of 1 metre. One gigajoule (one billion joules) is roughly equal to energy from 915 cubic feet of natural gas, 29 litres of gasoline, or 278 kWh of electricity.

kilowatt-hour 1,000 watt-hours.

load The amount of energy required by end-users on a given portion of the system at a given time. Load originates primarily at customers' energy-consuming equipment.

load growth Increase in the demand for energy.

load-resource balance The point at which demand for energy exactly equals energy production.

local distribution company (LDC) A utility (natural monopoly) that owns and operates the local delivery network for commodities such as electricity, natural gas and water. In a vertically integrated utility, local delivery is just one of several functions (e.g., BC Hydro). Thus, a LDC only exists when the delivery function has been vertically de-integrated (e.g., Terasen Gas).

market-based rates Prices set freely in a competitive market, rather than prices based on costs of production.

megawatt (MW) 1,000 kilowatts, or 1,000,000 watts.

natural monopoly An industry whose market output is produced at the lowest cost when production is concentrated in the hands of a single firm. The term utility is sometimes applied synonymously with natural monopoly.

natural gas marketer (NGM) (also see residential/commercial commodity alternative unbundling) Under the Commodity Unbundling program, natural gas marketers are independent businesses that offer gas supply choices to customers such as different terms and conditions. To be able to sell gas under the Commodity Unbundling program, gas marketers must be licensed by the British Columbia Utilities Commission and adhere to the Code of Conduct for Gas Marketers. (see <http://www.bcuw.com/NaturalGasMarketers.aspx>)

GLOSSARY OF TERMS

negotiated settlement process (NSP) A less formal process than a public hearing, and one where the applicant, interested parties and Commission staff meet to review and attempt to negotiate a settlement on some or all aspects of an application. NSP is used as a complement or an alternative to the traditional regulatory process [e.g., oral public or written hearings] in an effort to save time and reduce the cost of utility regulation while achieving sound regulatory outcomes.

peaking gas Gas which is stored or purchased under contracts which will allow delivery during the periods of highest demand.

performance-based rates See incentive regulation.

petajoule (PJ) 10¹⁵ or one quadrillion joules.

quasi-judicial The powers and processes of a regulator which are similar to the courts.

rate base The amount of investment in regulated operations on which a regulated entity is allowed to earn a return. It usually consists of the depreciated value of the plant in service required for regulated operations plus an allowance for working capital and deferred assets.

rate design The methodology for apportioning the revenue requirement to the various classes of utility customers.

rate rider A specific charge on a customer's bill to recover a specific cost over a fixed period of time.

ratepayers The customers of a utility.

rates The prices at which regulated services are provided.

real time pricing (RTP) Variable pricing of electricity in which the price depends on the cost or market value of providing electricity during each time segment. Applying RTP to electricity service results in customer rates that vary according to the specific utility costs at various times.

residential commodity unbundling [also see commercial commodity unbundling] The program provides residential customers (Rate 1) of Terasen Gas with the opportunity to enter into a natural gas commodity supply arrangement with a licensed gas marketer.

retail competition Permitting end-use energy customers to contract directly with energy suppliers for their electricity or natural gas commodity, while continuing to deal with transmission and distribution utilities for the commodity delivery. The energy commodity is generally sourced in a competitive marketplace.

return on equity (ROE) The percentage return allowed for the invested equity of utility shareholders.

revenue requirements See cost of service.

self-generation Generation of electricity by a customer for part or all of its own load requirements.

spot market A real-time commodity market for immediate sale and delivery of energy products.

time-of-use rates A rate structure that prices electricity at different rates, reflecting the changes in the utility's costs of providing electricity at different times of the day or year.

transmission grid, transportation grid, transmission system An interconnected system of high voltage energy transportation lines and associated facilities used for bulk transfers of electricity. A high-pressure pipeline used for bulk transfers of natural gas is also referred to as a transmission system.

watt The power required to do work at the rate of one joule per second.

watt-hour One watt-hour is equal to 3,600 joules of energy.

wheeling The service of delivering electricity across a transmission system for a third party.

wholesale markets Wholesale electricity markets are comprised of transactions between buyers and sellers of bulk power at points on a high voltage transmission system.

wholesale rates The unit prices charged for bulk energy services.

ENERGY CONVERSION FACTORS

Fuel Type	Original Measure	Terajoules
Coal	1 kilotonne	29.53
Coke	1 kilotonne	28.83
Petroleum Coke	1 megalitre	42.38
Natural Gas	1 gigalitre	38.35
Crude Oil	1 megalitre	38.51
Diesel Fuel Oil	1 megalitre	38.67
Light Fuel Oil	1 megalitre	38.67
Heavy Fuel Oil	1 megalitre	41.73
Aviation Gasoline	1 megalitre	33.52
Aviation Turbo Fuel	1 megalitre	35.93
Propane	1 megalitre	25.50
Butane	1 megalitre	28.60
Hydro-electricity	1 gigawatt hour	3.60
Thermal Electricity	1 gigawatt hour	3.60
Hog Fuel	1 megalitre SWE*	7.69 - 9.10
kilo..... 10^3	1 megalitre	1,000 cubic metres
mega..... 10^6	1 Btu.....	1054.615 joules
giga..... 10^9	1 barrel.....	0.15898 cubic metres
tera..... 10^{12}	1 cubic foot	0.02832784 cubic metres
peta..... 10^{15}	1 gallon.....	4.54609 litres
	1 standard cubic foot of natural gas	900-1000 Btus

* SWE = solid wood equivalent



British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, British Columbia, Canada V6Z 2N3
Telephone 604.660.4700
Facsimile 604.660.1102
British Columbia Toll Free 800.663.1385

General Inquiries & Filings
commission Secretary@bcuc.ca

Utility Customer Complaints
complaints@bcuc.ca

Natural Gas Marketing, Distribution Code Inquiries
customers@bcuc.ca

Website
www.bcu.com